

Transforming Dollars Into Sense:

The Economic and Environmental
Benefits of High-Efficiency
Distribution Transformers

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Prepared by:

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EXECUTIVE SUMMARY

Anticipating aggressive competition in the future deregulated electricity industry, U.S. utilities are investing in a variety of new customer-oriented businesses. These new ventures will provide enhanced customer service while reducing utility costs, improving system reliability and improving environmental performance.

In many cases the focus on new products and services has meant that expenditures on more traditional utility resources, such as new generation and transmission capacity, are either being reduced or passed on to unregulated subsidiaries. Investment in generation is no longer considered part of the core mission for electric utilities and has lost much of its relative importance for utilities and regulatory planners. This trend is further compounded by two factors: (1) reluctance of utilities to invest significant capital before the framework of a deregulated industry is clearly defined, and (2) the desire of many utilities to reduce short-term expenditures in order to provide lower customer rates.

Box ES-1

Potential Energy Savings and Emission Reductions with 1/10th of 1 Percent Increase in Efficiency

2.9 billion kWh

1,780,000 MT of CO₂

13,200 MT of SO₂

5,300 MT of NO_x

*Potential energy saved is enough for more than
a full day's electric power to all U.S.
households.*

Sources: EIA, ORNL, 1995.

The trend toward increased investment in products and services rather than system capacity presents a dilemma to both utilities and regulators. While new ventures will help utilities compete with non-regulated entities, the need remains for utilities to make long-term capital investments that ensure the reliable and cost-effective delivery of electricity. Unfortunately, regulators focusing on introducing market-driven reforms are reluctant to compel utilities to invest in specific projects or technologies.

Fortunately, utilities can implement a number of options that provide both system reliability and enhanced customer service. Investment in cost-effective high-efficiency

distribution transformers is one option that can help reduce utility costs while improving their competitive position under new industry structures.¹ This report examines why high-efficiency transformers may make sense for utilities preparing for a competitive future. The report also explores regulatory and institutional barriers that may discourage the use of high-efficiency transformers and suggest ways in which utilities and regulators can work together to reduce these barriers.

Why High-Efficiency Transformers?

Cost-effective high-efficiency transformers provide numerous short- and long-term benefits to utilities and their customers. These benefits include:

- *Reliable long-term energy and capacity savings.* The cost of energy saved using high-efficiency transformers is often less than two cents per kilowatt-hour, which compares favorably to the average cost of new generation (approximately \$0.03/kWh).² This low cost helps reduce long-term electric consumer rates;
- *Reduced investment in expensive transmission and distribution (T&D) capacity.* Strategic use of high-efficiency distribution transformers reduces the need for high-cost transmission upgrades;
- *Reliable air emissions reductions, often at no cost to utilities and their customers.* Most utilities do not include air emission compliance costs in their economic evaluations of transformer designs. In cases where the overall cost of high-efficiency transformers is no higher than the cost of a less efficient design, high-efficiency transformers provide emission reductions at no cost to the utility; and
- *Improved utility competitiveness through more efficient and reliable distribution systems.* Deregulation and the accompanying regulatory reforms (such as performance-based ratemaking) will make efficient operation of T&D systems more important to a utility's competitiveness and profitability. Utilities investing in high-efficiency transformers will be ensuring continued profitability.

¹ Throughout this report, references to "high-efficiency transformers" are intended to include both amorphous metal core transformers and high-efficiency silicon-steel core transformers, both of which can play an important role in reducing energy losses.

² Cost per kilowatt-hour saved based on a calculation methodology developed by the Lawrence Berkeley Laboratory as explained in Appendix A. New generation costs from *Annual Energy Review*, 1993, DOE/EIA-0384(93). July 1994.

Energy Savings and Emission Reductions

Despite the fact that average maximum efficiencies exceed 97 percent, significant cost-effective energy savings can be achieved using currently available transformer technologies.³ The long service lives of the approximately one million new transformers sold each year means that small efficiency gains can yield large lifetime energy savings and emission reductions. Box ES-1 shows the potential energy savings if the average efficiency of transformers sold to utilities in a single year were improved by just *one-tenth of one percent*.⁴

Failure to Invest in High-Efficiency Transformers Means Lost Opportunities

Utility investments in higher-efficiency transformers can lock-in long-term energy savings and emission reductions. On average, utility transformers remain in service for more than 30 years. The cost of installing a new transformer precludes replacing these transformers with more efficient designs unless the original transformer has been damaged or is malfunctioning. As a result, transformer purchase decisions made by a utility today have important and irreversible long-term economic and environmental impacts.

Why Aren't Utilities Making These Investments Now?

During the 1970s and 1980s, the average efficiency of distribution transformers steadily improved. However, over the past several years, the average efficiency of new transformers has begun to level out and may, in fact, be in decline. Although some of this decline is due to capital constraints brought on by the advent of competition, the mixed economic signals and incentives provided by the current regulatory framework are also to blame. Examples of regulatory barriers include:

³ Ibid.

⁴ These savings estimates are based on an increase in efficiency of one-tenth of one percent at 25 percent average load and result in a savings of 96.36 kWh per transformer per year. Assuming one million transformers sold and an expected 30-year average lifetime, results in a savings of 2.9 billion kWh. ORNL, 1995. Emission reduction estimates based on national figures from EIA's *Electric Power Annual* 1993. December 1994: 1.36 lbs (0.617 kg) of CO₂ per kWh, 0.01 lbs (0.00457 kg) of SO₂ per kWh, and 0.0041 lbs (0.00185 kg) of NO_x per kWh.

- ***Lags between transformer purchases and the recovery of the capital;***
- ***Uncertainty that only a portion of the capital invested in higher efficiency transformers will be recovered; and***
- ***The presence of fuel adjustment clauses, which may leave utilities and their shareholders indifferent to the benefits of investing in high-efficiency transformers.***⁵

What Can Be Done?

High-efficiency transformers can play an important role in increasing the competitiveness of electric utilities while meeting important utility objectives, including lower customer rates and reduced environmental impact of system energy losses. Advances in current transformer technologies have made their use both cost-effective and highly reliable. However, regulatory barriers must be addressed if the full economic and environmental benefits of high-efficiency transformers are to be realized.

The appropriate regulatory and utility actions to encourage investment in cost-effective high-efficiency transformers will depend upon the specific conditions in individual states. Regulators and utilities can take several steps to encourage appropriate investment in cost-effective high-efficiency transformers, including:

- ***Integrate supply-side resource options anticipating structural unbundling of the utility industry.*** As utilities procure energy on the open market, T&D system operations will become the critical determinant of utility competitiveness. Thus, current utility decisions regarding T&D system investments should receive increased consideration;
- ***Implement mechanisms that provide balanced incentives between cost-effective investments in high-efficiency transformers and other resource options;*** and
- ***Encourage utilities to participate in the EPA's ENERGY STAR Transformer Program,*** a voluntary program encouraging investment in cost-effective high-efficiency transformers. This Program provides a variety of technical tools to help utilities optimize their transformer sizing and selection decisions.

⁵ Morgan, R.E. "Time to Face FACS: How Fuel Clauses Undermine Energy Efficiency," *The Electricity Journal*, October 1993.

CHAPTER 1

INTRODUCTION TO

HIGH-EFFICIENCY TRANSFORMERS

The deregulation of the U.S. electricity industry promises to provide substantial benefits to consumers through lower electricity prices and enhanced services. As state and Federal regulators have begun to alter regulations to allow more industry competition, electric utilities have initiated aggressive cost-cutting programs designed to provide lower rates to their customers. While such actions may be an inevitable outcome of deregulation, regulators and utilities must also ensure that utilities continue to make sufficient investment in utility system infrastructure to assure the long-term safety and reliability of electricity service. Additionally, both utilities and regulators must guarantee that the environmental performance of utility operations does not decline under competition.

This report examines how cost-effective high-efficiency transformers can help utilities prepare for competition while reducing system energy losses and associated air emissions. It provides regulatory personnel and utilities with an overview of transformer technologies and explores how to overcome current regulatory and institutional barriers that discourage the use of high-efficiency transformers.

This document uses specific loading levels to illustrate the potential for energy and cost savings from high-efficiency transformer use. The loading levels were chosen to illustrate cost-effective high-efficiency transformer use. The selection of specific loading levels is not intended to imply that these levels are optimal or reflective of conditions found on all utility systems. In fact, transformer loading levels can vary widely depending on utility specific conditions and the end-users served by the transformer. Utilities and regulatory commissions considering increased investment in high-efficiency transformers should make such decisions only after careful consideration of the utility system loading patterns and of the specific transformer uses.

Past Policies and Legislation

Historically, supply-side efficiency options have not received the same regulatory scrutiny as more traditional utility resource options, such as generation projects, independent power production and demand-side management (DSM). However, several recent Federal actions have raised the profile of supply-side efficiency options (Box 1-1). The Energy Policy Act of 1992 (EPAc) directs states to investigate ways in which supply-side efficiency can be given more thorough consideration in utility resource planning processes.¹ EPAc contains a number of provisions related to supply-side and distribution transformer efficiency improvement.

The Climate Change Action Plan (CCAP), announced by President Clinton in October 1993, also encourages supply-side efficiency improvements by utilities. The *ENERGY STAR Transformer Program* (Action 30) promotes voluntary partnerships between transformer manufacturers, electric utilities, and EPA to increase the understanding of the benefits of cost-effective, high-efficiency transformers. The *ENERGY STAR Transformer Program* provides utilities and regulators with technical tools designed to maximize the use of cost-effective high-efficiency distribution transformers.

Launched in April 1995, the *ENERGY STAR Transformer Program* currently has 22 Utility Partners (representing approximately 10 percent of all U.S. sales) and 9

Box 1-1

Supply-Side Efficiency and The New Regulatory Structure

- The Energy Policy Act (EPAc) requires states to examine incentives/disincentives to investments in supply-side efficiency. (Section 111)
- The Climate Change Action Plan (CCAP) supports efforts to develop integrated resource planning processes in individual states.
- CCAP has led to the development of Climate Challenge, an umbrella program designed to encourage utilities to take actions, including supply-side efficiency measures, to reduce greenhouse gas emissions.
- CCAP Action 30 has led to the development of EPA's *ENERGY STAR Transformer Program*.

¹ Section 111 of the Energy Policy Act requires states to consider developing an integrated resource planning process to evaluate the "full range" of supply- and demand-side resources. In addition, Section 111 requires states and non-regulated utilities to consider the disincentives caused by existing ratemaking policies and practices and consider incentives that would encourage better maintenance and investment in more efficient power generation, transmission, and distribution equipment.

Manufacturing Partners (representing more than 80 percent of all U.S. sales). Utility Partners purchase and install transformers that qualify for the ENERGY STAR designation where cost-effective, while Manufacturing Partners agree to produce high-efficiency transformers and market them to their utility customers.

State regulatory policies are also beginning to change in ways that provide a greater impetus for the use of supply-side efficiency. Some state utility regulatory agencies have introduced limited performance-based ratemaking (PBR), eliminated or modified fuel adjustment clauses (FACs), and provided targeted incentives for specific utility investments. These mechanisms rely on market incentives to produce efficient, adequate, and reasonably-priced electricity service to utility customers. Supply-side efficiency improvements, including high-efficiency distribution transformers, comfortably fit within these new regulatory mechanisms and can provide cost-effective and reliable options for utilities and regulators seeking to meet the demands of a more competitive electric power industry.

The Many Benefits of High-Efficiency Transformers

Cost-effective high-efficiency distribution transformers offer significant benefits to electric utilities and their customers, even in the context of utility restructuring. The importance of distribution transformers to utility operations can be demonstrated by their overall contribution to system losses, as seen in the box at right.

Distribution Transformer Energy Losses

- 61 Billion kWh Every Year
- 26% of T&D System Losses
- 55% of Distribution Losses
- The Equivalent of Eight Days Generation from All U.S. Utility Power Plants

Aside from the pollution prevention benefits to society, high-efficiency transformers offer a number of benefits to utilities and their customers.

Cost Savings

Utilities own and maintain approximately 40 million distribution transformers and purchase approximately one million new units each year.² This enormous stock of transformers is often overlooked as a source of cost savings. Raising the average efficiency of a single year's sales of new transformers *by just one-tenth of one percent* could produce a lifetime transformer energy savings of more than 2.9 billion kilowatt hours (kWh). High-efficiency transformers also save energy at costs which are often lower than utility generation or other power supply options. The cost of saving a kWh of electricity ranges from \$0.007/kWh to \$0.03/kWh depending on transformer design and loading level, compared to the average price of new generation (approximately \$0.03/kWh).³

Reduced Air Emissions

This enormous stock of transformer additions is also often overlooked as a source of emission reductions. Small improvements in new transformer efficiency can significantly reduce the environmental impact of electricity generation. For instance, raising the average efficiency of a single year's sales of new transformers *by just one-tenth of one percent* would eliminate more than 1.78 million metric tons of CO₂, 13 thousand metric tons of SO₂, and five thousand metric tons of NO_x.⁴

Reliable, Long-Term Savings

Cost-effective high-efficiency transformers provide reliable, long-term savings. The physical characteristics and design of transformers allow them to produce immediate and virtually guaranteed energy savings. Thus realizing the benefits from their use is not contingent on uncertain planning and construction schedules or end-user behavior. This can help utilities substantially reduce administrative and monitoring costs, another critical consideration as utilities prepare for increased competition.

² ORNL, 1995.

³ Annual Energy Review, 1993, DOE/EIA-0384(93). July 1994.

⁴ ORNL estimates that the average efficiency of transformers in service is approximately 98.7 percent, based on a full-load core loss of 151 watts and winding loss of 423 watts. Assuming the average transformer is loaded at an estimated equivalent load of 25 percent over the course of an estimated 30 year lifetime, increasing the efficiency by 0.1 percent saves approximately 2.9 billion kWh of electricity. For a more detailed discussion of transformer efficiency and sources of energy losses see Chapter 3.

The failure of a utility to invest in cost-effective high-efficiency transformers will increase future transmission and distribution (T&D) costs and thus reduce competitiveness. Due to their high reliability, transformers can produce energy savings for 30 years or more. Utilities choosing lower first-cost equipment have essentially lost the opportunity for energy efficiency improvements and air emission reductions for thirty years or more.

Deferral of Expensive Capital Improvements

High-efficiency transformers can help utilities defer costly investments in new T&D capacity, one of the fastest growing utility expenditures.⁵ Deferring T&D investments can help to reduce the considerable legal and institutional costs of adding T&D capacity.

There is precedence for the use of efficient technologies to relieve system constraints. Several utilities have used DSM as a cost-effective way of meeting reduced demand in areas that otherwise would have required expansion of the T&D system.⁶ High-efficiency transformers can also be a cost-effective and more reliable method of deferring additional investments in transmission capacity.

Barriers to Transformer Efficiency Gains

High-efficiency transformers may not be purchased because of assumptions built into utility investment decisions and regulatory practices. As increased competition compels many utilities to reduce short-run costs in an effort to lower customer rates, supply- and demand-side efficiency programs, which have longer-term benefits, are being cut. However, the focus on the short-term implications often ignores both the long-term and irreversible consequences of utility actions and other less tangible benefits provided by supply-side efficiency technologies.

In addition, existing regulatory barriers discourage utilities from making investments in

⁵ Investor-owned electric utilities have increased T&D construction expenditures by approximately 0.5 billion dollars per year in the 1990s. *Electric World*, citing the Edison Electric Institute, May 1993.

⁶ See, *Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District*, Energy and Environmental Economics and PG&E, EPRI, TRANSFORMER 100487, May 1992, and *Best Current Practices in Integrating DSM into T&D Planning: Proceedings from the Second Annual Workshop*, prepared by Barakat & Chamberlin for EPRI.

high-efficiency distribution transformers. Specific examples include:

- FACs, under which fuel costs are passed on to consumers, blunting the incentive for utilities to optimize the efficiency of their operations;
- Lack of regulatory encouragement for consideration of supply-side efficiency measures; and
- Potential for a lag between investment in high-efficiency transformers and regulatory approval for the capital recovery.

The reduced investment in efficient technologies due to institutional and regulatory barriers presents an economic and environmental challenge to both utilities and regulators under any industry structure. However, the failure to address these barriers could also diminish a utility's long-run competitiveness under future industry scenarios, since failure to invest in efficiency will lead to higher distribution system costs, higher rates, and ultimately lower off-system sales. In some cases, there may be easily defined solutions to these barriers, such as reformulation or repeal of FACs.

In order to capture the full potential of high-efficiency transformers, utilities and regulators need to view transformer purchases as long-term strategic investments which can produce both improved economic and environmental efficiency. This report is intended to provide basic information on transformer economics and the institutional framework within which they are evaluated and purchased. The information provided in this report is intended to assist both regulatory commissions and utilities to ensure the optimal purchase of cost-effective high-efficiency transformers and other supply-side efficiency options.

Organization of this Report

The remainder of this report will provide additional detail on the mechanics and economics of distribution transformers, as well as the institutional framework within which utility purchase decisions are made. An introduction to transformer technologies can be found in Chapter 2. A discussion of the economics and energy saving potential of high-efficiency transformer use is contained in Chapter 3. The methods of utility examination of transformer purchases are discussed in detail in Chapter 4. Finally, an overview of the institutional and

regulatory barriers and potential solutions to these problems can be found in Chapter 5.

CHAPTER 2

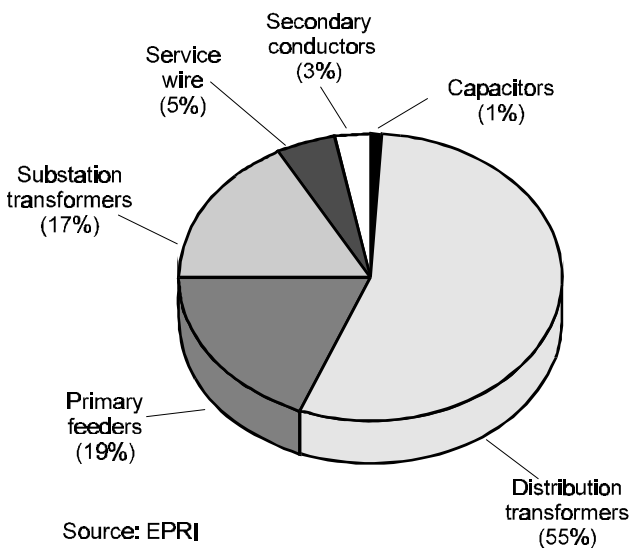
DISTRIBUTION TRANSFORMERS: TECHNOLOGY AND MARKET CHARACTERIZATION

Distribution transformers convert high-voltage electricity to lower voltage levels acceptable for use in homes and businesses. Approximately 40 million distribution transformers are in service on utility transmission and distribution (T&D) systems nationwide. Although individual distribution transformers are relatively efficient, these transformers as a whole account for 55 percent of the distribution system energy losses. (Figure 2-1).¹

An Overview of Utility Transmission and Distribution Systems

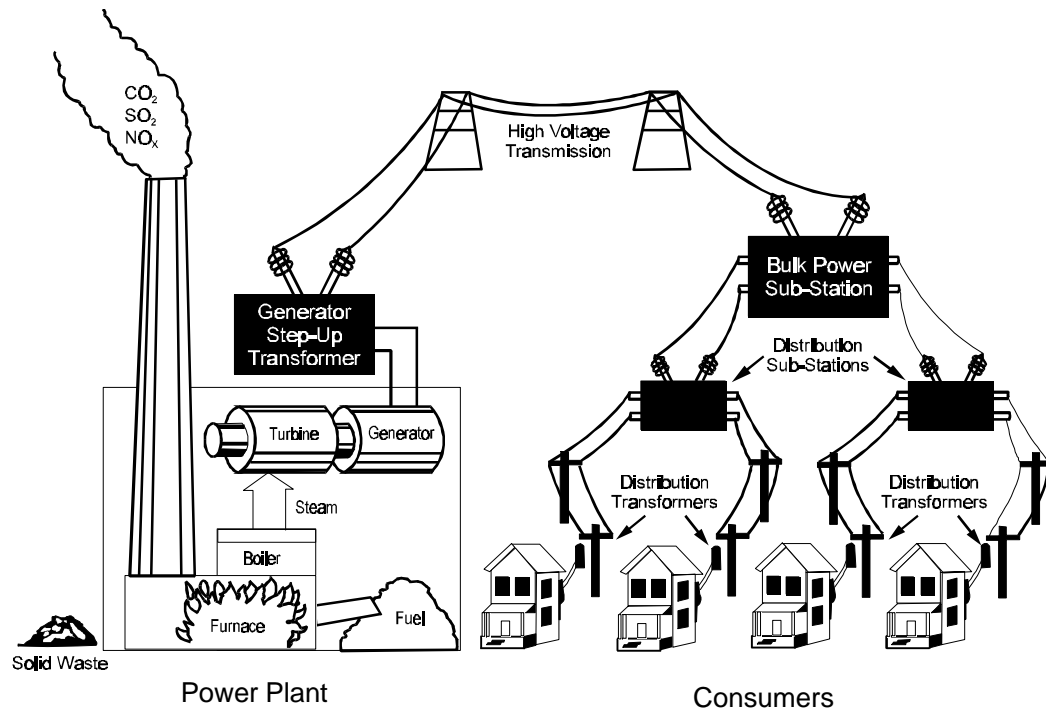
Utility T&D systems link electric generators with end users through a network of power lines and associated components (Figure 2-2). Typically, the transmission portion of the system is designated as operating at 69 kilovolts (kV) and above, while the distribution portion operates between 110 volts and 35 kV. A further distinction is often made between primary distribution (voltages between 2.4 and 35 kV) and secondary distribution (110 to 600 volt) systems. Industrial and commercial customers with large power demands often receive service directly from the primary distribution system. Most customers, however, receive service at secondary distribution voltages produced by stepping down primary voltages in distribution transformers.

Figure 2-1
Sources of Distribution System Losses



¹ This chapter draws on much of the data from ORNL, 1995. See also Marks, John. "Gaining on Losses," *Rural Electrification*, August 1994.

Figure 2-2
Generation, Transmission and
Distribution of Electricity



Transformer Design Characteristics

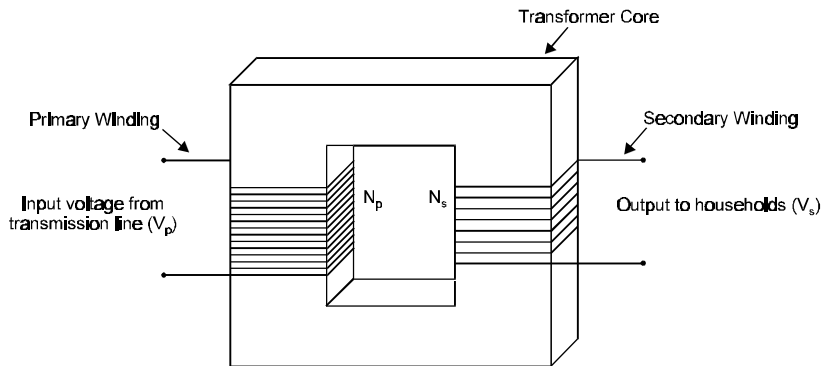
Transformers consist of two primary components:

- A core made of magnetically permeable material; and
- A conductor, or *winding*, typically made of a low resistance material such as aluminum or copper.

Distribution Transformer Basics

Copper or aluminum conductors are wound around a magnetic core to transform current from one voltage to another. Liquid insulation material or air surrounds the transformer core and conductors to cool and electrically insulate the transformer.

Figure 2-3
Typical Transformer Design



A transformer uses the core's magnetic properties and current in the primary winding (connected to the source of electricity) to induce a current in the secondary winding (connected to the output or load). Figure 2-3 illustrates a typical transformer design. Alternating current in the primary winding induces a magnetic flux in the core, which in turn induces a voltage in the secondary

winding. A voltage step-down results from the exchange of voltage for current, and its magnitude is determined by the ratio of turns in the primary and secondary windings. A transformer with 50 primary turns and five secondary turns would step the voltage down by a factor of 10, for example from 13,500 volts to 1,350 volts.

A given transformer's energy output is lower than the theoretical level specified by the nameplate rating due to inefficiencies in both the core and the windings.² In general, transformer losses are less than two percent of the total transformer load. The magnitude of the losses are dependent upon the loading of the transformer – core losses remain constant while winding losses increase with the square of the load. Thus, for a transformer with an average load of 25 percent, the core losses may represent approximately 75 percent of total energy losses; conversely at 100 percent of rated load, the winding losses may represent more than 80 percent of total energy losses. Thus,

Transformer Loss Basics

Core Losses are constant. *Winding Losses* increase exponentially (with the square of the load).

² Core losses primarily result from resistance to realignment of the magnetic domains in the core material and eddy currents. Winding losses result primarily from resistive heating losses in windings due to load currents and eddy currents. Losses also result from circulating currents in parallel windings and stray loss due to leakage fluxes in the windings. Of these winding losses, load and eddy current losses are the largest. Source: ORNL, 1995.

core losses make-up a greater share of total losses at lower transformer loads, while the winding losses make-up a greater share of total losses at higher transformer loads. The characteristics of transformer energy losses are described in further detail in Chapter 3.

Many different distribution transformer designs are available to utilities, depending on the loading patterns and needs of the end-user. Transformer engineers modify transformer design and vary material depending upon the needs of a particular utility (cost of energy, capacity, etc.). Transformer design includes variations of:

- (i) the material used for the core;
- (ii) the material used for the windings;
- (iii) the material that insulates the core and the winding;
- (iv) the number of phases of the current that passes through the transformer;
- (v) mounting; and
- (vi) the rated size.

The following section will describe the choices available to transformer engineers in greater detail.

Core Material

Transformer cores are usually made of either grain-oriented silicon steel or amorphous metal. Silicon steel comes in a variety of grades, each with its own conductive and efficiency characteristics. Amorphous metal, a more costly but highly efficient material, can significantly reduce core losses. The type of core material preferred by a utility is usually dependent on the cost of its core losses and the expected transformer loading levels. This subject is covered in more detail in Chapter 3.

Winding Material

Generally, copper and aluminum are used for transformer windings. As with silicon steel, these materials are available in a variety of grades and thicknesses, each with their own efficiency characteristics. The types of windings chosen by the transformer designer are also dependent on the cost of a specific utility's losses and on assumed transformer loading levels.

Insulating Material

The majority of utility distribution transformers are liquid filled. The non-conducting liquid (mineral oil is most commonly used) serves to electrically insulate and cool the transformer. Liquid-filled transformers transfer heat more efficiently than dry-type transformers. Commercial and industrial buildings predominantly use dry-type transformers due to safety concerns.

Phase

Most utility-owned distribution transformers are designed to step down a single alternating current from one voltage to another, and are thus called single-phase transformers. Certain applications require the use of a three-phase transformers, which contain three primary and three secondary windings. Three-phase transformers induce a more constant magnetic flux and output voltage desirable for motors, heating, ventilating, air-conditioning (HVAC) and other large equipment. Technically, the three-phase transformer is equally efficient to the single-phase transformer.

Mounting

Distribution transformers are either mounted on an overhead pole or on a concrete pad. Some observers believe that the average level at which the transformers are loaded differs between the two types.³ Since transmission lines traditionally have been run above ground, pole-top transformers comprise the majority of transformers in service on utility distribution systems (roughly 80 percent of single-phase units). The demand for pad-mounted transformers is increasing, however, and is currently greater than that for pole-type in areas where there is new housing construction.

³ According to one utility representative, utilities may load pole-mounted transformers more heavily than padmounts, as they are considered less likely to overheat. Other persons contacted for this study, however, suggested that the difference in loading between the two is not significant.

Nameplate Rating

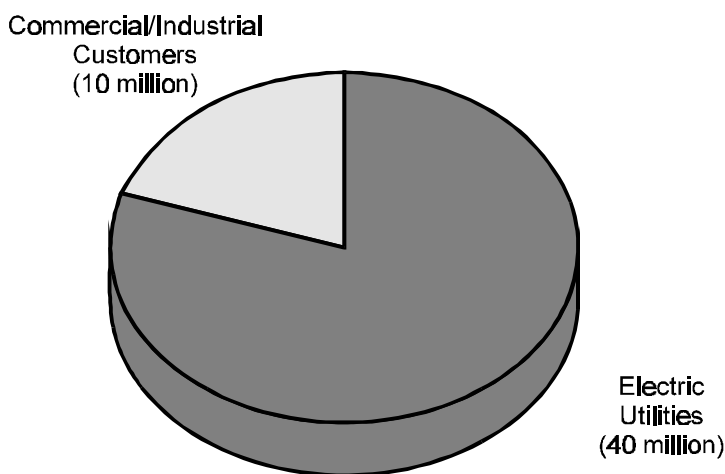
Transformer ratings are specified in kilovolt-amperes (or kVa), a product of the voltage and current at the "rated capacity."⁴ Distribution transformers range in size from less than 10-kVa to as much as 5,000 kVa. The nameplate rating designates the maximum capacity, or "load," the transformer is designed to handle. Thus, a 10-kVa transformer is operating at "full-load" when the demand on the transformer is 10 kilowatts (kW). In practice, transformers can operate at very high loads (i.e., 200 percent) for short periods. The ability of transformers to handle high loading levels is particularly important in residential applications, where demand may range from less than 10 percent during much of the day to over 200 percent for short peak periods. Properly sizing a transformer for a given application has a significant impact on the overall transformer efficiency and energy loss level. Predicting the range of loads as well as the average lifetime load level is difficult, and remains one of the most challenging tasks for utility T&D planners.

An Overview of the Market for Distribution Transformers

Figure 2-4

The majority of the 40 million utility distribution transformers nationwide serve residential and commercial customers. Commercial and industrial facilities own approximately 10 million additional distribution transformers that transform power purchased from utilities to lighting and power voltages (Figure 2-4). Utilities annually purchase and install

**Distribution Transformers By Ownership
(Units in Service)**



Source: ORNL 1995

⁴ One kilovolt amp (kVa) is roughly equivalent to a kilowatt (kW) of electricity. Kilowatts and kVa are related by power factor. This example assumes a power factor of one.

approximately 1 million new distribution transformers (liquid-filled, pole- and pad-mounted, single- and three-phase) .⁵

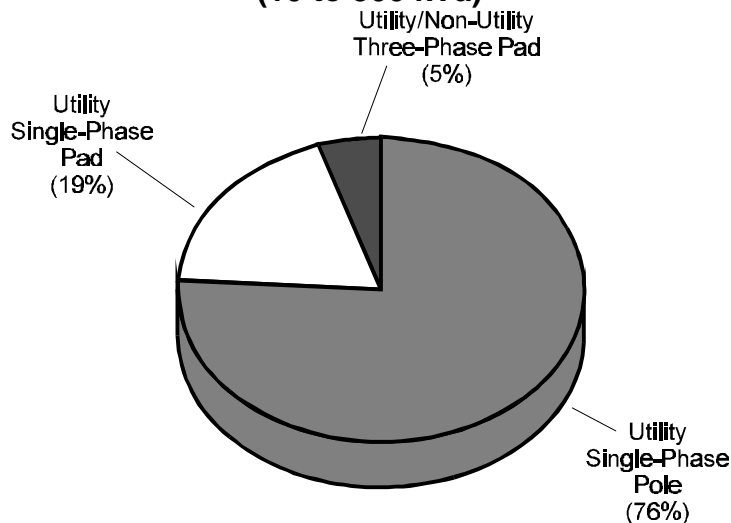
Most residential distribution transformers are single-phase and range in size from 10 kVa to 167 kVa, with 25 kVa being the most common rating. A transformer rating is chosen according to the expected application and loading patterns. For example, a utility may determine that 25 kVa transformers will serve four to five homes, depending on their system loading patterns, the type of housing stock, and the installed heating and cooling equipment. Another utility faced with similar demand may believe a larger transformer is necessary and install a larger 35 kVa transformer.

The types of transformers used in commercial applications vary widely, depending on the business and its energy end-uses. For example, if the majority of a business' load is for lighting or simple plug load, single-phase transformers may be an appropriate choice. However, businesses that have large motors, fans, and other equipment would be served mainly by three-phase pad-mounted transformers, ranging in size from 75 kVa to 2,500 kVa.

Annual Sales

Over 95 percent of transformer sales are single-phase distribution transformers ranging in size from 10 to 500 kVa (Figure 2-5). The remaining distribution transformer

Figure 2-5
Distribution Transformer Sales
(10 to 500 kVa)



Total Units: 963,000
Sources: NEMA, Square D

* Note: Data does not include 833 and 1000 kVa single-phase units; includes some three-phase units greater than 2500 kVa. Non-utility purchases of single-phase transformers are negligible.

⁵ ORNL, 1995.

Box 2-1		
Single-Phase Distribution Transformer Sales in 1993		
Nameplate Rating	Units Sold	Percent of Market
10 kVa	148,066	16
15 kVa	218,408	24
25 kVa	297,001	33
37.5 kVa	54,268	6
50 kVa	135,818	15
75 kVa	30,938	3
100 kVa	20,454	2
167 kVa	5,932	1
TOTAL	910,885	100

sales are three-phase units, most serving commercial and industrial customers. A detailed breakdown of single-phase transformer sales is presented in Box 2-1.

Transformer sales between 1996 and 2004 are expected to increase by approximately 1.7 percent per year, largely driven by utility replacements, new housing starts, and increased electricity sales (see Figure 2-6).⁶ Electric utilities estimate that net demand will increase by 39,019 Megawatts (MW) between 1994 and 2003; T&D systems will require new transformer purchases to handle this new customer load.

Energy Losses from New Distribution Transformers

Lifetime energy losses of lower efficiency distribution transformers installed this year will total approximately 30 billion kWh, and will result in the emission of more than 18 million metric tons of CO₂.⁷ Over the 30-year life of a transformer, each new average single-phase utility transformer will produce approximately 23 thousand kWh in energy losses, more than enough electricity for the annual needs of two average residential customers. Put another way, the annual losses of an average transformer could power a single residence for almost one month. An average 1000 kVa three-phase transformer will produce approximately 458 thousand kWh in losses over its lifetime, or enough electricity for almost 46 homes for one year.⁸

⁶ Electric Power Annual, 1993, DOE/EIA-0348(93). December 1994. See also ORNL, 1995.

⁷ Based on estimated annual losses of 1,004 million kWh for 30 years. National emissions and electric sales estimates from EIA's *Electric Power Annual 1993*. December 1994: 1.36 lbs (0.617 kg) of CO₂ per kWh, 0.01 lbs (0.00457 kg) of SO₂ per kWh, and 0.0041 lbs (0.00185 kg) of NO_x per kWh.

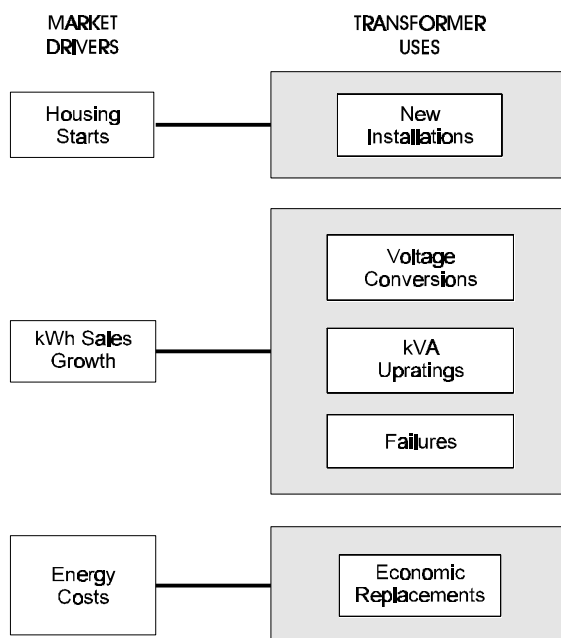
⁸ Based on total annual losses of 688 million kWh calculated from 913,973 units operating at an average estimated equivalent load of 25 percent over a 30-year lifetime (See Table 2-1). Home energy use levels based on approximately 10,000 kWh/year/home. Source : EIA's *Electric Power Annual 1993*. Three-phase estimated based on total annual losses of 191 million kWh calculated from 12,500 units operating at an average estimated equivalent load of 25 percent over a 30-year lifetime (see Table 2-1).

New, efficient transformer designs could reduce these energy losses and associated air emissions by 10 to more than 40 percent, depending on materials used and the loading pattern of the transformer.

An assessment of total energy losses from new distribution transformers, focusing on smaller single-phase transformers that significantly contribute to total losses, is presented in Table 2-1.

Figure 2-6

Transformer Installation Market



Source: *Electrical World*, 1991.

New Installations" of distribution transformers are for those areas of new construction in the residential or commercial sectors. "Voltage Conversions" occur when the utility customer installs totally new equipment with different voltage ratings. With "kVA Upratings," the utility customer installs new equipment and requires a higher capacity transformer. "Failures" are due to transformer operational or age factors and usually result in an emergency replacement. "Economic Replacements" are also known as early retirements. They may occur when energy prices paid by a utility are increasing rapidly and the losses from new transformers are much lower than for existing units, such that there is an economic justification for transformer replacement.

Figure 3

Table 2-1

**Average Annual Losses from New
Single- and Three-Phase Distribution Transformers**

Type and Nameplate Rating	Number of Units	Capacity (MVA)	Annual Losses (million kWh)
Single-phase (10-167 kVa) ¹	910,885	26,364	670
Single-phase (250-500 kVa)	3,088	1,113	18
Three-phase (avg. 150 kVa) ²	32,500	13,973	125
Three-phase (avg. 1000 kVa) ²	12,500	2,842	191
TOTAL	958,973	44,292	1,004

¹ Number of units added annually based on 1993 figures from NEMA.

² Number of units from industry sources and ORNL.

As Table 2-1 indicates, single-phase transformers from 10 to 167 kVa account for nearly 95 percent of the total transformers sold, but produce only about half of the annual losses. Larger single- and three-phase transformers contribute most significantly to new transformers energy losses. Large three-phase units, for

example, account for less one percent of units purchased annually, but contribute almost 20 percent of total energy losses. Despite the magnitude of these losses, three-phase transformers are generally more efficient than single-phase transformers, since most serve predictable end-user load demands. This allows utility engineers and transformer manufacturers to design transformers which conform more specifically to the load served and maximize overall efficiency.

Three-Phase Transformer Losses

Large three-phase units account for less than one percent of annual sales, but contribute nearly one-fifth of the total energy losses from new transformers.

Breakdown of Energy Losses for Single-Phase Transformers

Table 2-2 provides additional detail on the energy losses for new single-phase transformers.

Table 2-2
Summary of Average Annual Losses for Utility Single-Phase Transformers

Nameplate Rating	Full-load Loss (Watts) ¹		Per Unit Losses (Watts) ²	Number of Units Purchased	Total Annual Losses (million kWh)
	Core Loss	Winding Loss			
10 kVa	31	151	40.44	148,066	52.4
15 kVa	40	212	53.25	218,408	101.9
25 kVa	58	312	77.50	297,001	201.6
37.5 kVa	81	412	106.75	54,268	50.7
50 kVa	99	520	131.50	135,818	156.5
75 kVa	133	718	177.88	30,938	48.2
100 kVa	182	764	229.75	20,454	41.2
167 kVa	256	1350	340.38	5,932	17.7
TOTAL	--	--		910,885	670.22

¹ Source: Oak Ridge National Laboratory, 1995.

² Loss estimates assume transformers loading at an average estimated equivalent load of 25 percent. Numbers may not add due to rounding.

Sources: NEMA; 1993 Oak Ridge National Laboratory, 1995.

⁴ See pages A-2 and A-3 for the calculation of annual energy losses.

Examination of Table 2-2 reveals that 25 kVa transformers account for an estimated 30 percent of the losses for single-phase transformers, or approximately 200 million kWh. The next most common ratings, 15 and 50 kVa transformers contribute an additional 260 million kWh of annual energy losses. The majority of energy losses are assumed to be core loss due to the relatively low average loads assumed for single-phase transformers.

Conclusion

Utility distribution transformers account for 55 percent, or 61 billion kilowatt-hours, of distribution system losses. New transformer designs and proper sizing could reduce energy losses and associated air emissions by 10 to more than 40 percent, depending on materials used and the loading pattern of the transformer. Due to the significant number of transformers currently in service and the purchase of approximately 1 million new transformers each year, this is a subject that demands the attention of both utilities and regulators. Two cost-effective ways to reduce energy losses include: (1) the purchase of cost-effective high-efficiency transformers, and (2) the proper sizing of distribution transformers. The installation of approximately one million new transformers each year affords utilities a reliable and cost-effective opportunity to substantially reduce energy losses.

CHAPTER 3

POTENTIAL ENERGY SAVINGS FROM DISTRIBUTION TRANSFORMERS

Advances in transformer design have produced substantial transformer efficiency improvements over the past 20 years. The most significant improvements have been made in core technologies with the use of high-efficiency silicon-steel and amorphous metal. Despite the already high average efficiency of the current stock of transformers, increased use of these cost-effective new transformer designs could significantly reduce the 61 billion kilowatt-hours (kWh) lost due to distribution transformer inefficiencies each year.¹

Due to the large numbers of transformers in service and the constant nature of energy losses, only small increases in efficiency are needed to produce significant economic and environmental gains. For example, if the 25 kVa transformers sold today had the same efficiency as transformers sold 10 years ago, annual energy losses would increase by 80 million kWh annually, or nearly 40 percent above current levels.²

Similarly, improving the efficiency of utility transformers sold in a single year by one-half of one percent would reduce lifetime energy losses by 14 billion kWh and avoid the emission of 8.75 million metric tons of CO₂, 65 thousand metric tons of SO₂, and 26 thousand metric tons of NO_x.³ (Box 3-1)

Box 3-1

Lifetime Energy Savings and Emission Reductions with ½ of 1% Percent Increase in Efficiency

14.19 billion kWh
8,750,000 MT of CO₂
65,000 MT of SO₂
26,000 MT of NO_x

¹ ORNL, 1995.

² Efficiencies and losses are calculated at an average estimated loading of 25 percent. For load and no-load loss characteristics, ORNL-6804/R1, 1995, p.3.

³ Savings estimates assume a 0.5% increase in efficiency, 25 percent average load, a savings of 473.04 kWh per transformer per year, and one million transformers sold each with a 30-year lifetime.

To realize these energy savings, electric utilities must balance potential efficiency gains with the additional up-front costs of more efficient transformer designs. Utility transformer purchasing also requires careful consideration of several factors, including: (1) the average loading levels; (2) the cost of utility energy losses; (3) the cost of increasing core and winding efficiency; and (4) safety and reliability specifications.

Drivers of Efficiency

- Transformer loading and sizing.
- Cost of transformer losses.
- Cost of improving efficiency.

This chapter will discuss the factors that impact transformer efficiency and the ways in which transformer energy savings potential can be realized. In addition, it will consider the difficult trade-offs utilities often make between the higher initial cost of efficient transformers and the desire to lower customer costs in the short-run.

The Sources of Transformer Efficiency

Transformer energy losses can be reduced by improving the efficiency of the core or windings. The relative importance of core and winding losses depends on the loading on the transformer and the cost of each type of loss to the utility. Core losses occur continuously due to the need to keep the transformer energized and ready to serve

demand. Conversely, winding losses depend solely upon transformer load. Transformer winding losses increase by a factor of 100 when transformer load increases from 10 to 100 percent (0.1^2 vs 1^2), a common occurrence on residential service transformers.

Sources of Energy Losses

Core losses occur whether or not there is a load on the transformer. Because they are independent of load, core losses are sometimes called *no-load losses*.

Winding losses or load losses result from resistance in the windings, and vary in proportion to the square of the load. When a transformer is fully loaded, winding losses can represent 85 percent of total losses.

The importance of load factor on transformer losses is illustrated in Figure 3-1. At low-load levels, winding losses represent a relatively small share of total losses. However, when the transformer is operating at full load, winding losses can comprise between 80 and 85 percent of total energy losses.

Core Loss Reductions

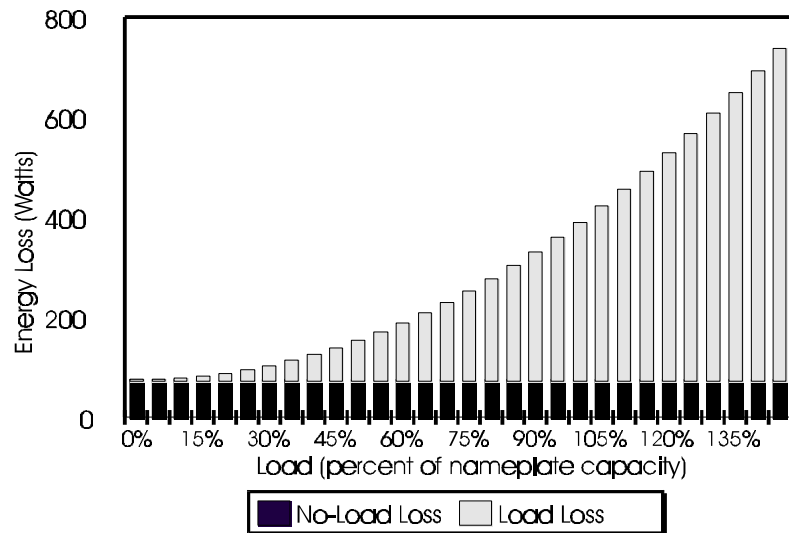
Because the majority of transformer losses at low load levels are due to core inefficiencies, much of the research on reducing transformer losses has concentrated on building more efficient cores. Core losses result from cyclic changes in the magnetic state of iron, and "eddy-current" losses caused by the flow of small currents in the iron. Core losses can be reduced by improving the magnetic permeability of the core material or by using a core material that offers less magnetic resistance.

Considerable progress in reducing core losses has been made over the past twenty years, primarily through material improvements. In the early 1970's, manufacturers introduced more efficient silicon-steels. The four main grades of silicon-steel used in transformers are M2, M3, M4, and M6 (decreasing in efficiency). Differences are due mainly to the chemical composition and the rolling techniques used in manufacture of the core. The increased domestic availability of higher grades of silicon-steel (M2 and M3) and new manufacturing processes has led to the improved efficiency of silicon-steel distribution transformers.

Amorphous metal, a highly efficient material used in transformer cores, possesses good magnetic properties, low inherent magnetic resistance losses, and high resistivity. Due to its ability to be constructed into very thin sheets, "eddy-current" losses are significantly reduced. Amorphous metals have been found to reduce core losses by as much as 70 percent.

Figure 3-1

The Effect of Transformer Load on Losses



However, the cost of transformers with more efficient cores increases due to the following factors. First, increasing core efficiency requires the use of more core material. Second, the larger core size associated with the energy-efficient transformer necessitates the use of additional winding material, generally resulting in lower winding efficiencies and other costs. In addition, the thin lamination of amorphous metal tends to make the core material more difficult to handle. Finally, certain types of efficient transformers may encounter specific problems, such as the difficulties associated with larger and heavier transformer design.

Winding Loss Reductions

Winding losses, or load-losses, arise from the conducting material's inherent resistance to the flow of electrical current. Winding losses increase with the square of the transformer load. Efficiency gains can be achieved by using materials with lower resistivity or greater diameters. For example, distribution transformer coils made with low resistivity conductors, such as copper, can have considerably lower load losses than those made with other materials. However, low resistivity conductors often cost more than other conducting materials.

Potential for Energy Efficiencies

Table 3-1 illustrates the potential for reducing energy losses due to more efficient core and winding materials. The base case gives a hypothetical transformer design, while the examples demonstrate the potential for efficiency gains through improved core and winding material.

Table 3-1

**Reduction in Transformer Losses with High-Efficiency Transformers
(Versus Standard Efficiency)⁴**

25 kVa oil-filled distribution transformer operated at 25% full load				
Losses (watts)	Base Case	Silicon 1	Silicon 2	Amorphous
Core	58	52	46	18
Winding	19.5	15.6	11.7	18.1
Total Losses	77.5	67.6	57.7	36.1
Percent Reduction in Losses	Base Case	12.8%	25.5%	53.4%

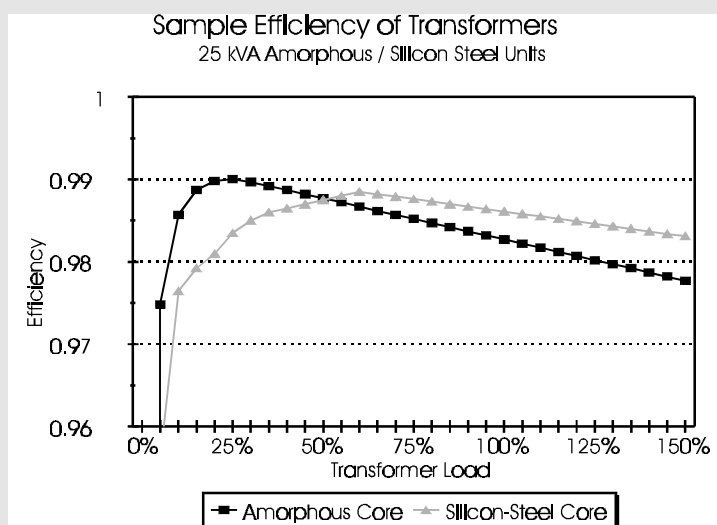
The Importance of Loading in Estimating Total Losses

Due to transformer energy loss characteristics, utilities must account for the expected loading level when making transformer purchasing decisions. Overall transformer efficiency depends critically on the percent of time that the transformer is heavily or lightly loaded. Although many utilities have studied this issue and collected loading data from transformers in service, uncertainties remain regarding transformer loading for customer classes during the 30-year life of the transformer. As a result, optimizing transformer design for efficiency remains a complicated task. Figure 3-2 illustrates the relationship between transformer load and efficiency.

⁴ Values for Base Case transformers from Oak Ridge National Laboratory (ORNL). Other transformer core and winding losses based on multiple manufacturers' data.

Figure 3-2
Impacts of Loading on Energy Losses of Transformers
with Different Loss Characteristics

Consider the efficiency curves of two hypothetical transformers (an amorphous core and a high-efficiency silicon-steel core transformer) presented below. These curves are derived solely from the core and conductor loss characteristics of the two transformers. Because the amorphous core transformer has lower core losses than the silicon-steel core transformer, it is more efficient at lower load levels. At these load levels, when most of total transformer losses result from core losses, the amorphous core transformer performs better. At higher load levels, however, core losses comprise a smaller share of total losses than load losses. Thus, the silicon-steel core transformers, which often have lower load losses, may be more efficient than the amorphous core transformers at higher load levels.



Transformer loading differs considerably by customer class. For example, residential transformers are often lightly loaded with significant peaks during short periods. As such, transformers must be designed to support peak morning and

evening loads. Because of the wide gap between peak and non-peak loads, and the relatively limited amount of time that the transformer is peak-loaded, average transformer loading tends to

Distribution transformers serving primarily residential loads often carry average loads that are only 15 percent to 20 percent of the transformer's rated capacity.

be fairly low, although precise estimates are difficult to derive.⁵ Larger distribution transformers, used more often in transforming power for commercial customers, tend to be loaded at higher average levels over the course of the year. Transformers that serve businesses operating from 9:00 am to 5:00 pm, for example, typically experience a consistent and relatively higher load throughout the day.

To further complicate matters, transformer loading patterns tend to change over time. Homeowners may accumulate more appliances and equipment, or businesses may expand and consequently increase the load on the transformer. Generally, utilities estimate load growth when sizing and purchasing transformers. Oak Ridge National Laboratory (ORNL) found that, on average, utilities size single-phase transformers so that transformer peak load at installation is approximately 88 percent of its capacity and 157 percent of capacity at the end of its service life.

The Importance of Sizing

As the previous discussion indicates, transformer loading and sizing are integrally related. Oversized transformers are lightly loaded, and consequently lose more energy from excess core losses than optimally sized

Oversizing transformers relative to the maximum loads expected to be placed on them results in inefficiency, due primarily to increased core losses.

transformers. Conversely, undersized transformers operate at higher load levels and experience high load losses. Some industry representatives believe that there is significant opportunity to realize both economic and efficiency gains through improved transformer sizing.⁶

However, optimal transformer sizing can be extremely complex due to the considerable variation in load and energy use within customer classes. For instance, residential use patterns are often dependent upon many different factors including: type of space conditioning; housing size and age; and economic factors. These many differing factors and the utility's need to ensure reliable electric service complicate the sizing decision making process.

⁵ One approach to estimating average load levels divides total residential and small commercial electricity demand (in kilowatts) by total installed capacity of transformers on the systems of utilities that service that demand. While ORNL does not provide precise numbers, it notes several studies that "indicate that transformers are lightly loaded most of the time, with short periods in which loads may be 50 to 100 percent above the rated load".

⁶ Cooper Power Systems, Waukesha, WI. Personal communication with ICF Incorporated, July 1994.

Table 3-2 illustrates the sizing dilemma. Depending upon the estimated load, the appropriate sizing of a transformer can minimize annual energy losses. Depending upon the design and core material, under or over-loading a transformer can result in significant annual energy losses.

Table 3-2
Sample Transformer Losses at Multiple Levels¹

Transformer Size	Core Loss	Winding Loss (Full-Load)	Annual Losses at Various Loads (kWh)			
			2.5 kVa	5 kVa	7.5 kVa	10 kVa
15 kVa	40	212	402	557	815	1,176
25 kVa	58	312	535	617	754	945

¹ Source: ORNL, 1995.

Although efforts have been made to develop technical tools to allow system engineers and field personnel to properly size transformers, these tools are not yet widely available. The U.S. Environmental Protection Agency (EPA), as part of the ENERGY STAR Transformer Program, has entered into an agreement with the Edison Electric Institute (EEI) in the development of technical tools designed to assist utilities in determining transformer size. These tools, which will be available in late 1996, will enable utilities to enter utility-specific loading information in order to optimize transformer size and total owning cost (TOC), while providing reliability and energy-efficiency.⁷

⁷ Technical tools designed to assist utilities in properly sizing transformers will be available in late 1996. Organizations that would like to receive these tools may do so by calling 1-888-STAR-YES (toll free).

Conclusion

Over the past 20 years, improved transformer designs and material advances have significantly increased transformer efficiency. Potential core efficiency has increased due to the availability of higher-grade silicon-steel and the development of amorphous metals. In addition to transformer design and material advances, transformer loading and sizing are important factors in improving transformer efficiency. An analysis of these factors can provide utilities with criteria to optimize their transformer purchasing decisions.

Higher efficiency transformers, however, increase up-front costs. The recent increase in competition and future deregulation have made many utilities unwilling to incur higher short-run costs. Weighing the desire to minimize short-run costs with the benefits of increased transformer efficiency, utilities are confronted with a relatively complicated decision making process in the purchase of distribution transformers. How utilities are attempting to reconcile the desire for more efficient transformers and the need to preserve capital is the topic of Chapter 4.

CHAPTER 4

UTILITY TRANSFORMER PURCHASING PRACTICES

Understanding how utilities balance technical and economic considerations in their transformer purchase decisions is an important step in devising strategies to promote increased transformer efficiency. The methodology used to evaluate alternative transformer designs can have significant implications on both the prices paid for transformers and the efficiency levels of the units purchased by a utility.

In general, utilities purchase transformers using economic evaluation techniques which consider price, energy losses, and the total owning cost (TOC) of the transformer. However, some utilities purchase transformers solely on the basis of the purchase price, while others consider a range of owning costs. Each method has different implications for transformer purchase patterns and, ultimately, for the energy losses and emissions associated with these transformers. TOC is the most sound means of analyzing transformer options, but the tools required to perform this analysis can be quite complex. Consequently, some utilities – particularly smaller ones – use simpler and less rigorous assessment methods.

As a general rule, more efficient transformers have higher up-front costs, although their lifetime, or total owning costs, will be lower. The current trend of utilities relying on lower purchase price, in order to relieve capital constraints and to reduce short-term customer electricity prices, has a significant impact on overall energy losses and associated air emissions over the life of a transformer.

This chapter provides an overview of the methodologies used by utilities to evaluate their transformer purchase options. It also discusses new evaluation practices that have evolved in response to industry restructuring. Finally, it suggests reasons why these practices may not result in the purchase of economically optimal transformers and the steps that can be taken to improve these practices.

The Total Owning Cost (TOC)

Methodology

Traditionally, utilities have evaluated transformer purchases using the TOC method, which accounts for the purchase price of the transformer and the present value of the cost of losses over the transformer's lifetime. The formula is generally expressed as follows:

Total Owning Cost

Total Owning Cost (TOC) is the method of economic analysis typically used by utilities to make transformer purchase decisions. TOC equals the sum of the cost of the transformer and the present value of the cost of losses from the transformer. In general, utilities attempt to minimize TOC.

$$\text{Total Owning Cost (TOC)} = (\text{Purchase Price}) + (\text{"A"} \times \text{No-load Losses}) + (\text{"B"} \times \text{Load Losses})$$

Where: A = levelized cost per rated watt of No-load Loss (termed the A factor)
 B = levelized cost per rated watt of Load Loss (termed the B factor)
 (30 year levelized costs)

Until recently, it was estimated that over 80 percent of all investor-owned utilities (IOUs) purchase transformers based on a TOC evaluation. However, evidence indicates that utilities are moving away from the TOC method towards a reliance on minimizing purchase price – a practice based solely on minimizing short-run capital expenditures. Due to the fact that the lowest first-cost transformer is usually the least efficient transformer purchase, this practice is likely to significantly increase overall energy losses and air emissions.

Calculating the TOC

The most complicated part of using a TOC methodology is estimating the present value of transformer energy losses. This calculation requires an estimate of what each watt of transformer core and winding loss will cost the utility over the thirty year life of the transformer.¹ The value of the A and B factors are dependent on a utility's avoided cost of generation, transmission, and distribution capacity, as well as the fuel, operation, and maintenance expenses

¹ As explained in Ch. 3, core losses, also known as "no-load" losses, result from the continuously energized state of the transformer and occur whether or not there is a load on the transformer. Winding losses, or "load losses," result from resistance in the windings and vary in proportion to the square of the load. See Ch. 2 for a more technical discussion of core and winding losses.

associated with the utility's energy supply. Expressed as dollars per watt for capacity and energy, these factors represent the costs to the utility over the life of the transformer for producing and delivering an additional unit of power to replace transformer energy losses.

Given the wide regional variations in system capacity costs, energy costs, and customer diversity, A and B factors differ significantly between utilities. For example, a utility in a region with low energy and capacity needs may have very low A and B factors, while a supply-constrained utility may have

relatively higher A and B factors. A and B factors may also vary among utilities based on the method and accuracy of the data used to estimate system energy and capacity costs.²

The Range of A and B Values Among Utilities

An Edison Electric Institute survey indicated that A factors generally range from \$1.00 to \$4.00; and B factors range from \$0.33 to \$1.80.

Avoided capacity and energy costs are used by utility planners to compare the cost-effectiveness of alternative resource options. Generally, the methodologies used to estimate avoided costs have been reviewed and approved by utility regulators as the benchmark for valuing all utility resources. Fair resource evaluations demand that identical avoided costs be used to evaluate each utility resource option.

However, certain utilities interviewed during the preparation of this report used differing avoided capacity and energy costs depending upon the resource analysis. Obviously, applying outdated or inaccurate avoided cost estimates will cause an electric utility to make sub-optimal resource allocation decisions. If transformer investments are to be evaluated fairly against other resource options, the system and energy costs used in TOC calculations must be consistent with the capacity and energy avoided costs used to evaluate generation and demand-side resource options.

² Several evaluation methodologies are available to utilities. General Electric Industrial & Power Systems presents three alternative methods of evaluating TOC: the equivalent first cost method; the annual cost method; and the present worth method. See *Guide for Evaluation of Distribution Transformers*, Draft 9305-1. August 1, 1994. In 1981, the Edison Electric Institute (EEI) published a report of the task force on distribution transformer evaluation that described a total owning cost method. This report presents a method for assessing the levelized annual total owning cost of distribution transformers. Stephen, Richard E. and John T. Shincovich. April 1981. *A Method for Economic Evaluation of Distribution Transformers: Part II. A User's Description of A Method for Distribution Transformer Evaluation*. Report of the EEI Task Force on Distribution Transformer Evaluation.

The Procurement Process

After determining its A and B factors, a utility will send both the factors and specific technical requirements to the manufacturers as part of its bid request. Where utilities purchase using the TOC method, manufacturers will use the A and B factors to design transformers that meet the utility's technical requirements and minimize total owning costs. Increasingly, manufacturers are submitting designs and bids that provide the utility differing resource objectives – some bids that minimize TOC while others that minimize purchase price. The lack of uniformity in utility A and B factors and other technical specifications have led manufacturers to develop customized transformer designs for most utility customers rather than offering “off-the-shelf” models.

Key Elements in the Transformer Bid Process

Utilities provide manufacturers with:

- Specific technical requirements
- A and B factors

Manufacturers provide utilities with:

- A range of transformer designs at the lowest TOC the manufacturer can meet

Utilities can select winning bids based on:

- Lowest TOC offered by bidders
- Lowest first cost for bids that fall within a specified TOC range
- Vendor evaluation criteria
- A combination of the above factors

Traditionally, utilities request annual bids for their transformer purchases. However, some utilities are now signing agreements with manufacturers to supply transformers over two or three year periods in an effort to reduce transformer procurement costs and build stronger relationships with key suppliers.

Selecting the Optimal Transformer

Using manufacturer bids which specify the core and winding losses of various transformer designs, utilities calculate the TOC of each transformer option. In some cases, even though energy losses and purchase price differ significantly, the two transformers may have identical TOCs (Box 4-1). Faced with this situation, many utilities will purchase the least costly unit (that with the lowest first cost) in order to preserve capital. In doing so, as the example in Box 4-1 illustrates, the transformer with the lowest up-front costs is also likely to be less efficient, and result in greater energy losses and pollution generation. The more efficient model would be

the better procurement option if the TOCs of two transformers are equal, and the utility has not considered the emission reduction benefits (e.g., internalized cost of emissions) in its evaluation of transformer costs.

Box 4-1

Same TOC, Different Efficiencies

The following table shows two hypothetical transformers that have the same total owning cost (TOC)

Transformer	Purchase Price	Lifetime Losses (kWh)	Value of Losses	TOC
Transformer A	\$505	36,930	\$223	\$728
Transformer B	\$540	33,120	\$188	\$728

Transformer B has significantly lower losses but costs about \$35 more than Transformer A. In many instances, utilities buy the less efficient transformer because it costs less initially, despite the fact that both have the same TOC.

TOC and the Multiplier

Utilities also consider “non-cost” factors which impact the results of the TOC method through the use of a multiplier. In general, these are considerations which can affect the security of supply and reliability of a specific manufacturer’s transformer. These considerations often include: a particular transformer model failure rate; past compliance with loss reduction guarantees; and the lead time required for transformer delivery. This information is used in determining each manufacturer’s pre-determined multiplier and applied to the TOC analysis. For example, a manufacturer designated with 1.0 would represent a preferred supplier based on past record; multipliers greater than 1.0 reflect some degree of utility uncertainty and thus have an impact of increasing the TOC of a particular transformer.

Band of Equivalence (BOE)

Increasingly, utilities are beginning to minimize the cost of transformer purchases due to the capital constraints brought on by the onset of future competition. As noted, many utilities purchase transformers according to the lowest purchase price. In order to do so, utilities have increasingly applied a “band of equivalence” (BOE) concept to the TOC. The BOE equates all transformer bids falling within a specified percentage range (typically one to five percent) of the lowest TOC. Using a BOE allows a utility to purchase the transformer with the lowest purchase price (and usually the highest losses) within that band. Purchasing transformers using a BOE thus increases lifetime transformer energy losses over those that would result from decisions made using a “hard” TOC evaluation. Although the BOE method helps utilities preserve capital in the short-run, it increases long-run utility costs and emission levels, as shown in Box 4-2.³

Box 4-2

How a Band of Equivalence Operates

A utility provides several manufacturers with its transformer specifications.
Two manufacturers respond with the following two transformer designs:

Transformer	Purchase Price	Lifetime Energy Losses (kWh)	Lifetime Present Value of Losses	TOC
Transformer A	\$700	33,120	\$532	\$1,232
Transformer B	\$640	39,090	\$629	\$1,269

With a 3 percent BOE, the utility would purchase Transformer B, because its TOC is within 3 percent of the TOC of Transformer A. Over a typical 30 year lifetime of the unit, Transformer B would lose 5,970 kWh more than the more efficient Transformer A. If this type of purchasing decision were extended to the entire 25 kVa transformer market, annual losses associated with new additions would amount to 58 million kWh.

Advocates of the BOE methodology justify its application due to the inherent uncertainty

³ In rare cases, the BOE has been used to select the transformer with the lowest losses rather than the lowest cost and, thus, to encourage the purchase of low loss transformers. In general, however, anecdotal evidence suggests that using a BOE results in a utility purchasing a less efficient transformer that the results of the TOC evaluation might underrate.

of future fuel and capacity estimates. They argue that since fuel and capacity price forecasts (and thus the values of future energy losses) are overstated, utilities cannot accurately anticipate the reduction in price of energy and capacity in a deregulated industry. Citing inaccurate forecasts of energy prices in the early 1980s and the misallocation of utility resources that resulted, advocates argue that the BOE methodology should be applied to the TOC analysis.

On the other hand, utility fuel and capacity price forecasts are typically the result of methodologies which have already accounted for the range of future trends, and have explicitly accounted for the uncertainty inherent in such forecasts. For example, utilities generally forecast a range of fuel price scenarios and use something near the median as the estimate of energy costs. Even if a utility forecasting process does not account for uncertainty, there are proven and methodologically sound ways of incorporating risk adjustments into forecasts. The BOE methodology does not appropriately incorporate risk uncertainty and should, thus, not be used in the TOC analysis process.

In addition, the BOE methodology double counts fuel and capacity price risk. As noted, the range of values is implicitly incorporated into most utility forecasts. Using the BOE to justify the purchase of lower cost and less efficient transformers effectively skews the process toward the lower forecasts, and in turn reduces the incentive for manufacturers to offer high-efficiency transformers in their bid proposal.⁴

Cost of Saved Energy Analysis

One of the most compelling justifications for the purchase of high-efficiency transformers is their ability to provide utilities with energy savings at costs lower than other resource options. In fact, a recent EPRI report compared high-efficiency transformers to other energy resources and found that the transformers were, in nearly every instance, the most cost-effective option. The cost-benefit ratio of amorphous core transformers versus new generation was generally

⁴ Evaluations based strictly on lowest TOC are known as "hard" evaluations. Some observers have estimated that more than 80 percent of the market for single phase distribution transformers are "soft" buyers, who apply a band of equivalence, or other factors, that distort the output of the TOC evaluation.

about 1.5/1.⁵ This would appear to be compelling justification for investigating the increased use of high-efficiency transformers.

However, it is unclear whether many utilities have analyzed how much it costs to save a kilowatt hour (kWh) of energy using high-efficiency transformers and compared it to other resource procurement options, such as new generation, and bulk and independent power purchases. Based on analysis performed in the preparation of this report, the levelized cost of saved energy (CSE) using high-efficiency transformers ranged between \$0.006/kWh - \$0.03/kWh, generally lower than the \$0.02- \$0.03/kWh estimated for new generation. While each utility's specific costs differ, this relatively low cost of energy saved provides further justification for the consideration of the purchase of cost-effective, high-efficiency transformers.

This section discusses the calculation of CSE using high-efficiency transformers. Because specific utility conditions may differ from those presented here, utilities and regulators are encouraged to conduct their own analyses using relevant cost and loading data to ensure optimal resource decisions are made.

Calculating Cost Per Kilowatt-Hour Saved

The method used in this report to determine the CSE was developed by the Lawrence Berkeley Laboratory.⁶ This methodology is described by the following formula, as it applies to transformers.⁷

⁵ Source: EPRI, "Cost Effectiveness Analysis of Amorphous Core Transformers using EPRI DSManager," EPRI TRANSFORMER-104246, Project 3127-09, October 1994, p. 5-4.

⁶ A more detailed analysis of CSE can be found in Appendix A.

⁷ Derived from *Principles of Corporate Finance*, Brealey & Myers (2nd edition). The discounting shown in the equation is also known as the annualization (or annuity) factor.

$$\text{CSE} = (\text{Incremental Cost of Transformer} / \text{Annual Energy Savings}) \times [I / \{1 - (1 + I)^{-n}\}],$$

where I = Real interest rate (Discount rate - Inflation rate)
 n = Equipment lifetime (30 years)

The sample calculation compares the CSE for two transformers shown in Table 4-1 where the real interest rate is levelized over a 30-year life of the transformers.

$$\begin{aligned} \text{CSE} &= (\$50 / 188 \text{ kWh}) \times [0.03 / \{1 - (1 + 0.03)^{-30}\}] \\ &= (\$50 / 188 \text{ kWh}) \times \{0.03 / (1 - 0.412)\} \\ &= \$0.0135 / \text{kWh, or 1.35 cents per kWh} \end{aligned}$$

To demonstrate a reasonable range of savings, Table 4-1 shows the data used to calculate the cost of saved energy for three hypothetical transformers (Units B, C, & D) as compared to a “typical” base case (Unit A).

Table 4-1
(25 kVa Single-Phase, Liquid-Filled Transformer)

Parameter	Unit A	Unit B**	Unit C**	Unit D**
Core Material	Silicon-Steel	Silicon-Steel	Silicon-Steel	Amorphous
Full-Load Efficiency Improvement	Base case	0.27%	0.54%	0.24%
Core (No-Load) Losses	58 Watts*	52 Watts	46 Watts	18 Watts
Winding Losses at Full-Load	312 Watts*	250 Watts	187 Watts	290 Watts
Incremental Cost	Base Case	\$50	\$95	\$180

* Transformer loss levels taken from ORNL (1994).

** Transformer efficiency, losses, and incremental cost are based on multiple manufacturers' data and do not represent a specific transformer design.

Cost of Saved Energy Results

Using the transformer designs shown in Table 4-1, CSE results were developed for each transformer at three equivalent transformer loads; 25, 50 and 75 percent of rated capacity. The calculation assumes a three percent real discount rate (eight percent discount rate and a five

percent inflation rate). The results are presented below.

Table 4-2

Saved Energy Results For Three Average Loading Configurations

Results @ 25% Load	Unit A	Unit B	Unit C	Unit D
Annual Energy Savings	Base Case	87 kWh	174 kWh	363 kWh
Cost of Saved Energy	Base Case	\$0.0295/kWh	\$0.0279/kWh	\$0.0253/kWh *
Results @ 50% Load	Unit A	Unit B	Unit C	Unit D
Annual Energy Savings	Base Case	188 kWh	379 kWh	398 kWh
Cost of Saved Energy	Base Case	\$0.0135/kWh	\$0.0128/kWh *	\$0.0230/kWh
Results @ 75% Load	Unit A	Unit B	Unit C	Unit D
Annual Energy Savings	Base Case	358 kWh	721 kWh	458 kWh
Cost of Saved Energy	Base Case	\$0.0071/kWh	\$0.0067/kWh *	\$0.0200/kWh

The range of CSE values table clearly demonstrates the impact of load and transformer design on the cost of energy saved. In addition, it demonstrates the fact that transformer can save energy at very attractive rates in comparison to other utility resource options: the CSE figures presented above are the equivalent of a utility purchasing firm, 30-year, emission-free, power for 0.7 to 2.9 cents/kWh. Again, the results may vary, but preliminary analysis indicates that cost-effective high-efficiency transformers provide a reliable method by which a utility can reduce both operating costs and customer rates.

Conclusion

Utilities typically evaluate and purchase transformers on the basis of the sum of the purchase price and the present value of unit energy losses – the TOC methodology is most widely used. Increasingly, however, utilities are making use of other untested analytical methodologies.

Although this is in part due to certain institutional barriers (e.g., inconsistent use of system capacity and energy costs), utilities have begun using certain untested methods (i.e., BOE) that attempt to address uncertainty. The result, however, is the purchase of a lower efficiency transformer despite higher TOC.

While the need to account for the uncertainty in future energy and capacity costs is necessary, utilities and regulators must ensure that the methods used are both consistent with the uncertainty of analytical techniques used for other utility resources, and based on methodologically sound principles. Without these assurances, utilities may purchase sub-optimal transformer equipment that irreversibly produce higher lifetime energy losses, higher long-term rates for utility customers, and increased air emissions.

Due to the long-term implications of transformer purchases, it is critical that utilities operate under a clear set of principles during this transitional period. At a minimum, utility evaluation techniques need to be consistent with other utility procurement practices, account for the role of uncertainty in their long-term equipment purchases, and account in some way for the additional non-economic benefits that high-efficiency transformers can provide.

In addition to evaluating transformer purchases with appropriate methodological analyses, there are a number of institutional and regulatory barriers that tend to inhibit the purchase of high-efficiency transformers. Utilities purchase transformers with respect to complex and often contradictory institutional and regulatory rules. Current institutional and regulatory barriers that exist as a detriment to the use of cost-effective high-efficiency transformers are discussed in Chapter 5.

CHAPTER 5

OVERCOMING REGULATORY BARRIERS TO IMPROVED TRANSFORMER EFFICIENCY

Transformer purchasing decisions are made in a business and regulatory environment that often presents utilities with conflicting incentives. Rules established for utility resource decisions can present barriers to the purchase of efficient distribution transformers. The effects of these rules are exacerbated by the capital constraints under which many utilities currently operate. The following regulatory barriers can reduce utility incentive to invest in high-efficiency transformers and other supply-side efficiency options:

- Resource planning processes that fail to fully consider cost-effective supply-side efficiency opportunities;
- Fuel adjustment clauses (FACs) eliminating shareholder incentives for utilities to maximize fuel cost savings and system efficiency improvements;
- The time lag between the investment in high-efficiency transformers and the recovery on expenditures in rate cases;
- Retrospective prudence reviews; and
- Uncertainty surrounding electric industry competition and the allocation of stranded costs.

Recent federal policy initiatives, including the Energy Policy Act of 1992 (EPAAct) and the Climate Change Action Plan (CCAP), encourage consideration of supply-side efficiency improvements as a means of achieving cost-effective energy savings and emission reductions. Despite these efforts, to date there has not been sufficient activity to produce significant supply-side efficiency gains. State regulatory policies and practices should be examined to determine if they present barriers to full consideration and implementation of cost-effective supply-side efficiency investments. This chapter describes the existing policy context and outlines options for state utility regulators to consider and ensure that barriers to high-efficiency distribution transformers are reduced.

The Policy Context

Over the past several years, many federal actions have attempted to raise the profile of supply-side energy efficiency measures as a means of reducing utility costs and emission levels. EPCa contains a number of provisions related to supply-side efficiency improvement and distribution transformer efficiency. Section 111 of EPCa builds a foundation for states and utilities to give new attention to supply-side efficiency through Integrated Resource Planning (IRP) processes, specifically requiring all states to consider developing such processes to evaluate a "full range" of supply and demand resources. From the supply-side efficiency perspective, the most important provision in Section 111 requires state regulatory authorities to examine the disincentives caused by existing rate making policies and practices, and consider incentives that would encourage better maintenance. In addition, it requires state regulatory authorities to consider and encourage the investment in more efficient power generation, transmission, and distribution equipment.

To assist the states, the National Association of Regulatory Utility Commissioners (NARUC) is preparing a study tentatively entitled: *Electric Utility Supply-Side Efficiency and Integrated Resource Planning*.¹ In its abstract for the proposed study, NARUC identified two potential obstacles to states' fulfillment of the EPCa Section 111 mandate: (1) many commissions are unaware of the potential for supply-side energy savings, and (2) that should such potential be recognized, commissions may not "be aware of many of the insidious regulatory barriers that exist." The study has three primary purposes:

- To provide examples of the readily available efficiency improvement opportunities at existing supply facilities;
- To provide a comprehensive discussion of regulatory policies and practices (i.e., fuel adjustment clauses) that "may discourage utilities from improving the efficiency of their facilities"; and
- To provide descriptions of alternative regulatory responses to these perceived barriers.

Another major federal effort is CCAP, launched by President Clinton in October 1993, as

¹ National Association of Regulatory Utility Commissioners (NARUC). July 15, 1994. *Electric Utility Supply-Side Efficiency and Integrated Resource Planning* - Funding Proposal Submitted to the U.S. Department of Energy.

a means of reducing U.S. emissions of greenhouse gases to 1990 levels by the year 2000. The CCAP includes a provision that relates to the creation of the U.S. EPA *ENERGY STAR Transformer Program* in order to encourage the accelerated deployment of high-efficiency transformers.

Launched in April 1995, the *ENERGY STAR Transformer Program* encourages Utility Partners to purchase and install high-efficiency transformers, while Manufacturing Partners agree to produce and market high-efficiency transformers to utilities. In addition to these transformer-specific actions, CCAP also supports increased efforts to develop sound, IRP processes in the individual states.

Although federal policies provide clear direction, utility investment in cost-effective supply-side efficiency measures will require a significant effort at the utility and state regulatory level. This chapter discusses the regulatory barriers which discourage such investments, and presents a variety of reforms which could improve the equitable and economically rational consideration of supply-side efficiency improvements at the state level.

Utility Regulation in a More Competitive Environment

Encouraging the efficient use of resources while also providing operational flexibility is one of the biggest challenges regulators face as the industry moves toward greater competition. In response to increase competition, utilities have begun to cut operating costs, minimize retail rates and strengthen cash flow. Convincing utilities to invest in cost-effective long-term investments presents a significant and real challenge.² Energy-efficient investment is exacerbated by the fact that many long-term supply side investments have similar total owning costs but significantly different efficiency characteristics, as seen in the examples of distribution transformers in Chapter 4. In most cases, utilities are investing in the lowest cost and highest loss transformers, thereby eliminating the opportunity to realize energy savings over the 30 year life of the transformer.

The advent of competition is prompting some regulators to rethink the conventional

² According to an American Council for an Energy-Efficient Economy (ACEEE) report, several large utilities involved with DSM programs decreased their spending from 10 percent to 60 percent between 1994 and 1995. *Transmission & Distribution World*. "T&D Spending Patterns," p.55-61. January 1996.

resource planning models built around formal regulatory review of utility plans and specific resource choices.³ Even in states where regulators envision retaining some basic responsibility for resource planning, many are considering new approaches which simplify the process and introduce market-oriented incentives into the utility decision making process.

Despite the moves toward alternative regulatory mechanisms, most regulatory commissions indicate that they have not placed supply-side efficiency high on the regulatory agenda.⁴ It appears that while regulators are interested in supply-side efficiency, it has been difficult to position this issue as one warranting special attention.

Moving Towards Resource Planning Integration in a Competitive Environment

In every competitive market, winning firms are those that maximize productivity in the long-run. Minimizing transformer losses, where cost-effective, enhances productivity. Therefore, in addition to legitimate public policy reasons for promoting energy efficiency on both the demand- and supply-side, there is a strong business rationale for increasing distribution transformer efficiency. Ensuring that supply-side efficiency opportunities are not overlooked may require utilities and regulators to increase their efforts to encourage a truly integrated approach to planning.

However, as utility resource choices are being influenced by competitive pressures, cost-cutting has become a primary objective. Utilities are reluctant to invest in more expensive technologies that have longer pay-off periods. In order to ensure that the potential for profitability and efficiency enhancements are not lost due to the failure to consider all resource options (both long- and short-term), a sound strategic resource planning process is essential for both utilities and regulators.

³ The California Public Utilities Commission proposed a major restructuring of the utility industry in the State, including abolition of the biennial resource planning process. See *Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation*, R.94-04-031, April 20, 1994.

⁴ Staff from the Colorado, New York, and Florida utility commissions, and the Illinois Department of Energy. Personal communication with ICF Incorporated.

Challenges to Integrating Transmission & Distribution Into Resource Planning

Supply-side efficiency investments can provide utilities with a cost-effective means of increasing reliability, lowering emissions and deferring other system upgrades. In theory, regulatory commissions direct utilities to give full consideration to all resource options, but in practice utility resource plans have typically focused on cost-effective deferral of utility fossil generation by demand side management (DSM), renewable resources, and non-utility power. While utilities often include some supply-side resource measures (such as fossil generation repowering), these options are presented primarily as a means of increasing system capacity rather than to improve the efficiency of electricity transmission and distribution (T&D).

Leveling The Playing Field For Supply-Side Efficiency Investments

- Modify fuel adjustment clauses
- Provide consistent financial incentives for all resource options
- Ensure that cost-recovery mechanisms do not favor specific investments
- Use performance-based ratemaking tools

One of the largest barriers to the full realization of supply-side efficiency improvements arises from the functional separation of T&D planning and other resource planning within utilities. Typically, T&D upgrades are considered as a way to improve the delivery of generation to load and to protect system reliability, rather than as a means of conserving system resources. Conversely, utility generation and demand-side resource planning has generally focused on meeting new customer demand. Failing to realize the ability of supply-side efficiency to meet increased energy demand, utilities are not considering the full range of cost-effective resource investment options.

This separation between resource planning processes can also result in the use of different avoided costs by utility T&D engineers and other resource planners. In applying inconsistent avoided costs to its resource options, there is a potential to misallocate funds, and thus not choose an option that provides both cost reduction and energy efficiency.

The regulatory systems governing resource planning and traditional transformer purchasing processes reflect these differences. In most cases, generation and demand-side

resource planning analyses use a base case and several sensitivity analyses to estimate the consequences of changing key parameters, such as demand growth or costs. These analyses are carefully considered by utilities and regulators in their investment decision making.

Conversely, uncertainty in supply-side efficiency planning is either ignored or handled in a manner that is inconsistent with other resource planning analyses. For instance, as discussed in Chapter 4, many utilities use a band of equivalence (BOE) in transformer purchasing decisions as a means of accounting for fuel and capacity cost uncertainty. However, utility forecasts typically have accounted or corrected for this uncertainty; therefore, additional correction via a BOE is unnecessary and inappropriate.

Integrating Supply-Side Efficiency into Resource Planning

The most obvious way to encourage the integration of supply-side efficiency options into resource planning is to modify existing rules governing resource plan filings. In addition to their new generation, power purchase and DSM analyses, utilities would provide cost and benefit assessments for a predetermined set of supply-side efficiency measures. These side-by-side assessments would ensure that the evaluation of the costs and benefits of each option is derived using identical avoided costs and uncertainty methodologies.

To Encourage Integration of T&D and Traditional Resource Planning, Regulators Could:

- Explicitly request that utilities present an assessment of the costs and benefits of high-efficiency transformers and other distribution investments in the resource plans..
- Ask utilities to analyze supply-side efficiency improvements using the same avoided costs used to assess DSM and new resource options.
- Investigate the best method to account for uncertainty in transformer purchasing practices.

Incorporating supply-side efficiency options into utility resource plans, however cost-effective, will not guarantee that such measures will be adopted by utilities if other regulatory policies create disincentives for their use. Any comprehensive approach to ensuring the maximum use of cost-effective supply-side efficiency measures, such as high-efficiency transformers, must include an examination of how existing policies may provide financial

disincentives for supply-side efficiency measures vis-a-vis other resource options. Providing a balanced set of incentives between all resource options should be a high priority for regulators as utilities move into a more competitive market.

The following sections will discuss the most significant barriers to the investment in supply-side efficiency options and suggest possible alternative ratemaking options available to state regulators.

Modifying Fuel Adjustment Clauses

Approximately 40 states have fuel adjustment clauses (FACs) that enable the costs resulting from price changes to be passed on to or recovered from utility consumers.⁵ Initially developed in the 1970s, FACs were primarily designed to insulate utilities from the financial consequences of fuel price swings. Although FAC mechanisms vary significantly, the basic structures are quite similar. Any utility expenses or savings resulting from deviations in fuel prices from the level forecast in rate proceedings are passed on to customers through a surcharge or credit to the electricity rate. A large number of the FACs in place are "fully reconciled" fuel clauses, which allow utilities to flow-through all increases and decreases in fuel costs associated with either operational changes and/or changes in fuel prices. Many FACs also allow the flow-through of costs from increased power purchases due to generating plant outages.

The practical effect of fully reconciled FACs is to reduce or eliminate the utility incentive to maximize efficiency, since any resulting savings is directly passed on to consumers. This encourages the utility to invest in activities for which it receives a return on investment (e.g., new generation and DSM) while limiting the amount of utility capital available for measures which improve supply-side system efficiency.

A variety of options exist for modifying FACs to ensure that they do not present barriers to utility investments in supply-side efficiency. Two general options are: (1) including system efficiency standards in the fuel adjustment calculation; and (2) limiting the use of FACs to changes in fuel prices. In their simplest form, FACs include a surcharge or credit per kilowatt

⁵ For a fully discussion of the operation and incentives introduced by fuel adjustment clauses, see Morgan, R. E. October 1993. "Time to Face FACs: How Fuel Clauses Undermine Energy Efficiency," *The Electricity Journal*.

hour (kWh) on electricity sales to compensate for the difference between actual fuel costs and forecast fuel costs. Including a supply-side efficiency standard, such as a heat rate or line loss standard into the FAC, would prevent a utility from recovering increased costs when system performance falls below the standard. More importantly, such a mechanism would reward the utility for improving system performance by allowing it to retain the resulting fuel cost savings. At the next rate proceeding, the regulatory agency could establish the standard at the new efficiency level to encourage the utility to investigate further improvements in system performance due to improved performance between base rate periods.⁶ Additionally, since the primary function of FACs is to protect the utility from fuel price volatility, they could be modified to allow the automatic pass-through of only costs directly associated with fuel price changes.

Both options are consistent with the original purpose of the FAC to provide some protection against factors over which the utility has no control. However, both leave at least a portion of the potential reward and risk for efficient system operation with the utility.

Regulatory Lag and the Electric Revenue Adjustment Mechanism (ERAM)

In general, regulatory ratemaking does not allow utilities to immediately recover increases in capital investments. In the typical rate case proceeding, state public utility commissions (PUCs) examine either historical or forecasted utility expenses to establish a price for electricity that is expected to earn the utility a specified rate of return. Therefore, in between rate cases, utilities maximize profits by reducing operating costs or increasing power sales. Expenditures to improve system efficiency in excess of those estimated in the rate case proceeding may be recovered, but usually not until the next rate case. This so-called “regulatory lag” provides an incentive for improved operating efficiency in the short-term, but discourages utility investment in longer-term efficiency improvements.

To avoid this problem, some PUCs have developed mechanisms which allow modifications of utility energy charges between base rate cases. These mechanisms, the most prevalent of which is California’s ERAM, could be applied to distribution transformers and other supply-side efficiency options as well.

⁶ See Morgan, *op. cit.*

Pre-approval of Supply-Side Efficiency Options

Many PUCs regularly conduct retrospective reviews of the prudence of utility capital investments. Any investments deemed to be economically unjustified or unwarranted are disallowed by the regulators for purposes of utility rate recovery. The disallowance of utility DSM expenditures by numerous regulatory agencies over the past several years has made utilities wary of investing large amounts of capital without prior and explicit regulatory approval. One solution to this problem could be for regulators to encourage utilities to ask for pre-approval of recovery of expenditures on high-efficiency transformers and other supply-side efficiency options.

Creating Balanced Incentives for Improved Supply-Side Efficiency

In the past, many utilities have not invested in efficiency measures since such measures did not earn a rate of return. In recent years, regulators have introduced mechanisms which reward utilities for investments in DSM. These mechanisms could be adapted to supply-side efficiency investments, achieving the overall goal of providing supply-side efficiency investments equal consideration with other utility resource options.

Another way to stimulate investment in supply-side efficiency options is to include a rate-of-return (ROR) adjustment for utilities that meet pre-determined distribution system efficiency targets. This approach can be an effective way of encouraging the installation of more high-efficiency transformers and other supply-side efficiency measures. Another benefit is that utility performance is relatively easy to monitor. However, setting the appropriate efficiency level can be difficult and contentious.⁷

The regulatory mechanisms described above can be effective in encouraging utility investment in high-efficiency distribution systems, including transformers. However, like any policy aimed at encouraging particular resource choices, these targeted incentives can have effects that extend beyond utility distribution purchases when applied within the current regulatory

⁷ One approach often used in setting performance targets of indices is to identify a "benchmark" company that demonstrates an ability to achieve superior performance in its operations. The level of incentive would be set as a function of how a utility matched-up against this benchmark. As with virtually any such approach, no two utilities are ever entirely comparable. Nevertheless, it is possible to develop reasonable adjustments to allow for uncontrollable differences between companies. For example, in the case of a transformer incentive program, these differences could include type of load and load profiles.

framework. In fact, the typical application of ROR regulation in the context of utility rate setting creates a confusing amalgam of incentives and disincentives for efficient utility operation.⁸ Correcting this perceived weakness of the existing system by introducing additional mechanisms designed to focus utility attention on other investments may simply compound the original problem and create more confusion.

The complexity and oversight required under traditional ROR regulation has prompted an increasing number of state regulators to consider new ratemaking methodologies which are generally referred to as performance-based ratemaking (PBR) mechanisms. These new regulatory systems are designed to provide utilities with incentives to behave like competitive unregulated firms, and to reduce the effects of inconsistent regulatory signals on utility decision making. PBR can offer a variety of incentives to utilities and can eliminate or reduce the need utility rate cases. California, Illinois, Oregon, Massachusetts, Washington, and Wisconsin are currently experimenting with performance-based systems. These systems are discussed in the following section.

Performance-Based Ratemaking

Three performance-based systems will be described here: price cap regulation; revenue cap regulation; and rate-of-return indexation.⁹ None of the PBR mechanisms have been fully applied to the electric utility industry for a significant period of time; therefore, their success in promoting more efficient utility operation is generally untested. However, these mechanisms could help ensure that utilities are given the freedom to maximize their investments in measures that provide greatest value for both their customers and their shareholders.

Price Cap Regulation

⁸ For example, the Averch Johnson effect suggests that, since allowed utility profits are the product of the value of the rate base and the authorized rate-of-return, a utility will maximize its capital investments in an effort to maximize its rate base, and thus profits, when its expected return exceeds its cost of capital. When expected returns are less than the utility's cost of capital, the theory suggests that the company will avoid investment. This effect was discussed by Harvey Averch and Leland Johnson in "Behavior of the Firm Under Regulatory Constraint," *The American Economic Review*, December, 1992. Other perspectives suggest that as utility markets become more competitive utilities will attempt to minimize rate increases and improve cash flow by cutting expenses and investments.

⁹ See Brown, L, Einhorn, M., and Vogelsang, I. (1989) *Incentive Regulation: a Research Report*, Federal Energy Regulatory Commission, Office of Economic Policy, November 1989.

In its simplest form, price cap regulation establishes an electricity price based on a cost-of-service methodology. The utility is allowed to alter this price only to account for inflation, less a predetermined productivity gain. If the utility is able to improve productivity by more than the target amount, its profits increase. If it can not meet the basic productivity target, its profits decline.

Under price caps, if utility efficiency improvements allow it to produce a kilowatt hour (kWh) on the margin for less than its average cost, the utility's costs will decline and profits increase. Thus, in theory, this type of regulation should provide an incentive to increase the use of cost-effective supply-side efficiency measures, including distribution transformers. However, if care is not taken in the design of the system, a price cap system might encourage short-term productivity gains achieved by cost-cutting to the detriment of long-term productivity gains produced by efficiency-enhancing investments.

Revenue Cap Regulation

Revenue cap regulation is similar to price cap regulation, except that utility revenues, not prices, are capped and indexed.¹⁰ A key difference between the two systems is that a revenue cap should make a utility indifferent to whether it profits by improving efficiency or by increasing electricity use. Any revenue reduction resulting from DSM savings is automatically recouped by the utility. Under a price-cap, revenues lost to DSM cannot be recovered.¹¹ Under a revenue cap, however, the incentive to improve supply-side efficiency could be lower since utilities essentially are encouraged to cut costs rather than increase productivity. This tendency could be reduced by tying any change in the cap to productivity gains.

Indexing the Rate-of-Return to Measures of Efficiency

The total factor productivity (TFP) approach is a form of PBR that lies somewhere between the types of incentive regulation described above and price- or revenue-cap regulation. TFP ties utility earnings to an index or indices of system operating efficiency either in absolute

¹⁰ Revenue cap regulation really is an extension of the concept of "decoupling" that has been applied in several states as a way to remove the disincentive to utility DSM caused by lost revenues.

¹¹ A price cap system could be modified to allow a utility to recover lost revenues through a separate DSM price index.

terms (i.e., earnings are tied to the change in the subject utility's productivity) or relative terms (i.e., earnings are tied to a utility's productivity relative to a benchmark utility). Unlike price or revenue cap regulation, a utility can earn increased earnings only by improving its productivity, as opposed to simply cutting costs, which might not yield a sustainable increase in productivity. To date, some limited forms of this approach have been tried for factor inputs such as purchased power and fuel supply procurement.

As shown by these examples, PBR may provide more economically viable opportunities for the installation of high-efficiency transformers. Under PBR, utilities may be judged on the efficiency of their T&D system. As efficiencies increase with the use of high-efficiency distribution transformers, utilities would be able to earn a higher ROR.

Conclusion

Utilities may experience both institutional and regulatory barriers to optimal investments in cost-effective, high-efficiency transformers. Regulators and utilities need to work together to reduce or remove these barriers. Some potential solutions include:

- Implementing mechanisms that ensure a level playing field between supply-side efficiency options and other resource options;
- Encouraging the full integration of T&D and traditional resource planning;
- Promoting investments in cost-effective high-efficiency transformers through ratemaking reforms, including performance-based ratemaking; and
- Developing specific incentives for distribution efficiency—such as rate of return adjustments and expedition of cost-recovery for long-term efficiency investments.

The intent of these measures should not be to skew the decision making process toward the use of high-efficiency transformers, but rather to ensure that all resource options are considered equally and provide an incentive to invest in those measures which provide the highest economic and environmental value.

The importance of treating investments in supply-side efficiency equitably will become more critical as utility generation resources are increasingly deregulated, leaving utility T&D

systems the main focus of the traditional utility and its regulators. Ensuring the optimal use of utility T&D systems will require the creativity of both utilities and their regulators. However, once the regulatory barriers are removed, high-efficiency distribution transformers will prove to be an excellent and cost-effective means to enhance both long-term utility profits and the environmental performance of utility systems.

APPENDIX A

CALCULATING THE COST OF TRANSFORMER EFFICIENCY

Introduction

When purchasing transformers, there are several methods that can be used to perform an economic analysis. Some decision makers will use a lowest first cost method, while a majority of decision makers at utilities will use the total owning cost (TOC) methodology.

The TOC methodology, as shown throughout this report, is used primarily by investor-owned electric utilities, using utility specific variables (known as "A" factor and "B" factor) that account for capitalized costs per rated watt at no-load and full-load conditions. These values are derived using utility specific capital, fuel, generation, transmission, operation, and maintenance costs, along with customer demographics (e.g., mostly residential customers with specific transformer loading characteristics).

Key Parameters

To accurately perform the economic analysis, several parameters must be defined. The key characteristics for transformer analysis are as follows:

- Insulation (liquid-filled or dry type)
- Rated capacity (in kVA)
- Location (pad-mount or pole-mount)
- Core materials (silicon steel or amorphous metal) and winding materials (copper or aluminum)
- Electrical characteristics of equipment served (single-phase or three-phase)
- Efficiency at part-loads and full-load
- Core (no-load) and coil (load) losses, in Watts or kW
- Temperature adjustment to coil (load) losses
- Initial capital cost
- Electricity cost, in cents/kWh
- Transformer loading characteristics (constant versus variable loads, percent of rated capacity)
- Discount rate, in percent

All of the parameters will have an impact on the economic analysis of distribution transformers. Manufacturers catalogues typically list insulation type, capacity, core and winding materials, part-load and full-load efficiencies, core losses, and coil losses.

Formulas to Determine Annual Energy Losses

To analyze the economics of distribution transformers, the following formulas should be used.

Wattage Losses

To determine the wattage losses for the standard and high-efficiency distribution transformers, the following equation is used:

$$\text{Losses} = \text{NLL} + \{ [(\% \text{ Load})^2 \times \text{LL}] \times \text{TA} \}$$

where NLL = No-Load (core) Losses in Watts

% Load = Percent of full load rated capacity being used

LL = Load (coil) Losses at rated capacity in Watts

TA = Temperature adjustment (if applicable)

Annual Transformer Energy Losses

To determine the annual energy losses in kWh for transformers, the losses from the previous equation should be converted to kiloWatts (1000 Watts = 1 kiloWatt) and the following formula should be used:

$$\begin{aligned}
 \text{Annual Energy Losses} = & \quad (\text{kW losses at a \% load}_1) \times (\text{Hours/year at \% load}_1) \\
 & + \quad (\text{kW losses at a \% load}_2) \times (\text{Hours/year at \% load}_2) \\
 & \cdot \\
 & \cdot \\
 & + \quad (\text{kW losses at a \% load}_n) \times (\text{Hours/year at \% load}_n)
 \end{aligned}$$

where n = Number of load conditions during the year (e.g., 4000 hours at a "low" load, 4000 hours at a "medium" load, and 760 hours at a "high" load correspond to n equal to 3)

Annual Transformer Energy Loss Cost

To determine the annual energy costs for distribution transformers, the formula is:

$$\begin{aligned}
 \text{Annual Energy Costs} = & \quad (\text{kWh/year loss at \% load}_1) \times (\text{Value of electricity in \$ / kWh}_1) \\
 & + \quad (\text{kWh/year loss at \% load}_2) \times (\text{Value of electricity in \$ / kWh}_2) \\
 & \cdot \\
 & \cdot \\
 & + \quad (\text{kWh/year loss at \% load}_n) \times (\text{Value of electricity in \$ / kWh}_n)
 \end{aligned}$$

where n = Number of load conditions during the year (e.g., 4000 hours at a "low" load, 4000 hours at a "medium" load, and 760 hours at a "high" load correspond to n equal to 3)

Simple Payback

To determine the simple payback for the purchase of a high-efficiency distribution transformer, the formula is as follows:

$$\text{Simple Payback} = \quad \text{Incremental Cost of High-Efficiency Equipment} / \text{Annual \$ Savings}$$

Cost of Saved Energy

To determine the cost of saved energy (CSE), the nominal (real) interest rate, incremental cost of the high-efficiency unit, and the annual energy saved per year of the equipment life are used. The primary method to calculate the CSE was developed by the Lawrence Berkeley Laboratory:

$$\text{CSE} = (\text{Incremental Cost} / \text{Annual Energy Savings}) \times [I / \{1 - (1 + I)^{-n}\}]$$

where I = Real interest rate (Discount rate - Inflation rate)
 n = Equipment lifetime

The discounting shown in the equation is also known as the annualization (or annuity) factor, as derived from *Principles of Corporate Finance* by Brealey & Myers (2nd edition).

If the annual energy savings fluctuate significantly over the life of the equipment, a weighted average annual energy savings can be used in the denominator. Table A-3 shows the two transformers to be analyzed.

Sample Calculations - Cost of Saved Energy

There are several parameters that must be defined when performing a cost of saved energy (CSE) analysis. In the following example, two transformers will be analyzed for the cost of saved energy. The transformer information and energy usage calculations are shown below.

For this analysis, the following operational and economic conditions are used:

- The load on the transformer is constant and is continuous.
- The average lifetime load is 12.50 kVA (50 percent of the rated capacity).
- There are no coil loss temperature adjustments due to cooler temperatures at partial load.
- The value of electricity losses is \$0.06 per kWh.
- The discount rate is eight percent for the sample company or utility.
- The inflation rate is assumed to be five percent, which results in a nominal (effective) interest rate of three percent.

For the comparison between transformers A and B, the CSE is calculated as shown:

$$\text{CSE} = (\text{Incremental Cost} / \text{Annual Energy Savings}) \times [I / \{1 - (1 + I)^{-n}\}]$$

where I = Real interest rate (Discount rate - Inflation rate)
 n = Equipment lifetime

$$\begin{aligned} \text{CSE} &= (\$50 / 188 \text{ kWh}) \times [0.03 / \{1 - (1 + 0.03)^{-30}\}] \\ &= (\$50 / 188 \text{ kWh}) \times \{0.03 / (1 - 0.412)\} \\ &= \$0.0136 / \text{kWh, or 1.36 cents per kWh} \end{aligned}$$

Table A-1
Transformer Analysis - Cost of Saved Energy Results

Result	Unit A	Unit B
Incremental Cost	Base Case	\$50
Annual Energy Savings	Base Case	217 kWh
Equipment Lifetime	30 years	30 years
Nominal Interest Rate	3%	3%
Cost of Saved Energy	Base Case	\$0.0136/kWh

Different transformer loss characteristics, incremental costs, and load factors will result in a wide range of costs of saved energy. For the above example, transformers with an average lifetime loading factor of 75 percent will result in a CSE of \$0.0071 per kWh. If the transformers have an average lifetime loading factor of 25 percent, the calculations would reveal a CSE of \$0.0293 per kWh.

Sample Calculations for First Cost/Simple Payback Approach

Using the parameters shown in Table A-3, a first cost and simple payback method can be used to analyze the transformers.

As shown in Table A-2, the standard unit has annual energy losses of 1,191 kWh. The high-efficiency unit has annual losses of 1,003 kWh.

The simple payback is calculated with the following formulas:

$$\begin{aligned}\text{Annual Energy Savings} &= 1,191 \text{ kWh} - 1,003 \text{ kWh} \\ &= 188 \text{ kWh per year}\end{aligned}$$

At a value for electricity of \$0.06 per kWh, the annual costs savings are as follows:

$$\begin{aligned}\text{Annual Cost Savings} &= 188 \text{ kWh} * \$0.06 \text{ per kWh} \\ &= \$11 \text{ per year}\end{aligned}$$

The high-efficiency unit has an incremental cost of \$50. The simple payback is:

$$\begin{aligned}\text{Simple Payback} &= \text{Incremental Cost of High-Efficiency Equipment} / \text{Annual \$ Savings} \\ &= \$50 / \$11 = 4.5 \text{ years}\end{aligned}$$

The calculations for annual energy losses, annual operating costs, and simple payback are summarized in the following table:

Table A-2
Transformer Analysis - Simple Payback Results

Operating Conditions	Standard Unit	High-Efficiency Unit	Savings/Results
Annual Energy Losses	1,191 kWh	1,003 kWh	188 kWh
Incremental Cost	Base Case	\$50	(\$50)
Annual Operating Cost	\$71	\$60	\$11
Simple Payback			4.5 years

Table A-3

Specifications for Two Sample Transformers

Parameter	"Standard" Unit A	"High-Efficiency" Unit B
Rated Capacity	25 kVA	25 kVA
Insulation	Liquid-filled	Liquid-filled
Percent of Full-Load Operation	50%	50%
Core Material	Silicon-Steel	Silicon-Steel
Electrical Phase	Single-Phase	Single-Phase
Full-Load Efficiency Increase	Base Case	0.5%
Core (No-Load) Losses	58 Watts*	52 Watts**
Coil Losses at Full-Load	312 Watts*	250 Watts**
Annual Energy Losses	1,191 kWh	1,003 kWh
Temperature Loss Adjustment	n/a	n/a
Incremental Cost	Base Case	\$50

*Values for typical transformers as shown in the Oak Ridge National Laboratory report entitled *Determination Analysis of Energy Conservation Standards for Distribution Transformers*.

**These values correspond to a 10 percent reduction in core losses and a 20 percent reduction in the coil losses at full-load and do not represent any particular transformer on the market.

NOTE: The load on the transformer is an estimated average load over the 30-year life.

Energy Calculations

In this example, the standard transformer A losses are:

$$\begin{aligned}
 \text{Losses} &= 58 \text{ Watts} + (0.5)^2 \times 312 \text{ Watts} \\
 &= 136 \text{ Watts (0.136 kW)}
 \end{aligned}$$

For the standard transformer, the annual energy losses calculation is:

$$\begin{aligned}
 \text{Annual Energy Losses} &= 0.136 \text{ kW} \times 8,760 \text{ hours} \\
 &= 1,191 \text{ kWh}
 \end{aligned}$$

In this example, the high-efficiency transformer B losses are:

$$\begin{aligned}\text{Losses} &= 52 \text{ Watts} + (0.5)^2 \times 250 \text{ Watts} \\ &= 114.5 \text{ Watts (0.1145 kW)}\end{aligned}$$

For the high-efficiency transformer B, the annual energy losses calculation is:

$$\begin{aligned}\text{Annual Energy Losses} &= 0.1145 \text{ kW} \times 8,760 \text{ hours} \\ &= 1,003 \text{ kWh}\end{aligned}$$